A PUBLIC POLICY ANALYSIS OF COAL UTILIZATION FOR ELECTRIC POWER GENERATION IN NEW ENGLAND

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ABSTRACT

Coal provided a significant portion of New England's energy requirements until 1966. Then, the elimination of tariffs on imported residual oil and the introduction of environmental regulations caused coal consumption to become minimal in the region. In light of possible future federal legislation to require the use of coal in new steam-electric power plants, a study was conducted to reevaluate the economic and environmental acceptability of coal utilization in New England for electric power generation. The addition of a single new coal-fired power plant at Salem, Massachusetts, was the analysis scenario.

The environmental analysis considered air pollution from coal combustion and its control. The cost of controlling particulate, sulfur oxide, and nitrogen oxide emissions using existing technologies were estimated, as were the calculated maximum 24-hour ambient concentrations of these pollutants within 70 kilometers of the plant. Tradeoff curves relating the cost of sulfur oxide control to sulfur oxide emissions and ambient concentrations were developed.

The economic analysis estimated the busbar cost of electricity from a coal-fired plant in 1978 dollars. The best estimates of busbar costs showed that coal-fired generation which satisfied all air quality regulations would be approximately 6 per cent less than comparable oil-fired generation in 1978 for base and intermediate-load applications. The major factor in the competitiveness of coal with oil was determined to be the difference in delivered fuel prices.

Coal utilization was then discussed from the perspective of a Massachusetts public policymaker. It was concluded that coal utilization would minimize energy costs and maximize the security of energy supply to the region compared with imported oil. Though all applicable air quality regulations could be satisfied, possible health effects at ambient pollutant levels below current standards were discussed. Also, the effect of coal combustion on acid-sulfate aerosol levels was estimated and determined to be small. Currently uncontrolled pollutants such as heavy metals, fine particulates, and sulfates were highlighted as areas requiring further investigation. Other policy issues which affected the economics analysis were the current status of flue gas desulfurization systems, the future trend of coal prices under long-term contract, and the adequacy of the railroads in New England for the large-scale movement of coal by unit trains.

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TABLE OF CONTENTS

Page

LIST OF FIGURES

LIST OF TABLES

PREFACE

Since the oil embargo imposed against the United States by the Organization of Petroleum Exporting Countries (OPEC) there has been an abundance of comment and debate as to what ought to be done in terms of public policies on energy, but that which has actually been accomplished has been meager. The formulation of substantive environmental policy by the executive and legislative branches of government in recent years has been similarly limited. Such a lack of policy can be attributed in part to two characteristic aspects of energy and environmental problems which impede their speedy resolution by public policymakers. First, an inadequate data base to support thoroughly informed judgments exists in nearly all facets of any given energy or environmental issue. And second, politically disadvantageous tradeoffs between competing, if not mutually exclusive, public objectives must frequently be made in order for a policy to be adopted. Policy formulation is hindered by uncertainty and political expediency.

One alternative for policymakers faced with this dilemma is to postpone any decision until adequate data is available or until the political climate is more favorable for making the necessary tradeoffs. Unfortunately for the policymaker, postponement is not always possible, for compelling circumstances arise which require that policy decisions be made before it is either politically convenient to do so or before it is possible to have complete information. Thus, it would behoove the policymaker and the policy analyst to be prepared to deal with such a contingency.

The central problem of this thesis, a public policy analysis of coal utilization in New England, has provided an excellent opportunity for the author to examine a typical energy-cum-environmental policy issue. The

scenario is a realistic and currently relevant one. And, in addition, the analysis has had to cope with a shortage of "hard" economic and environmental data and has had to reconcile tradeoffs between conflicting public objectives. In short, this thesis has been a valuable introduction for the author to problems that confront the public policymaker.

CHAPTER 1. INTRODUCTION

1.1 Background on Energy in New England

The New England states are confronted with a serious energy problem which may eventually damage the economic viability of the region, if it has not done so already. This problem is characterized by a large and unfavorable disparity of energy costs in New England vis-a-vis the rest of the nation. For example, current electricity costs in New England are up to 90 per cent higher than in some regions of the country and 52 per cent higher than the national average: 4.1 cents per kilowatt-hour in New England versus an average of 2.7 cents per kilowatt-hour for the United States [1]. As energy costs increase and become a larger component of individual and business budgets, the impact of the energy cost disparity on the region will also increase.

Unfortunately for the New England consumer, their energy problem is an inherent one whose origins are natural and not man-made. It can be attributed in large measure to the lack of exploitable indigenous energy resources in the region, with the exception of wood and water power (both are significant resources, but wholly inadequate compared with the overall energy needs of the region) [2]. Consequently, energy resources must be transported over large distances from either foreign or domestic suppliers to New England. In the case of fossil fuels, transportation adds substantially to the delivered price of fuel.

For electricity generation, few alternatives are available over the medium term, say the next 15 to 30 years, which could significantly diminish the energy cost disparity. One alternative is certainly to accelerate the construction of nuclear power plants for which fuel and fuel

transportation costs are small, because only a few hundred metric tons of fuel are required per year. It is not surprising that New England electric utilities have already invested heavily in nuclear plants and that nuclear power currently comprises 17 per cent of the total capacity of the New England Power Pool (NEPOOL) compared with an 8 per cent contribution to the total nationwide capacity. It is projected by 1985 to comprise 37 per cent of NEPOOL capacity. However, it is unlikely to greatly exceed this percentage since the nuclear option is limited primarily to base-load applications. Because of its high capital costs, the fuel cost advantage disappears rapidly as the plant's load factor decreases. Regulatory problems which currently beset the nuclear industry may also hinder the future development of nuclear power.

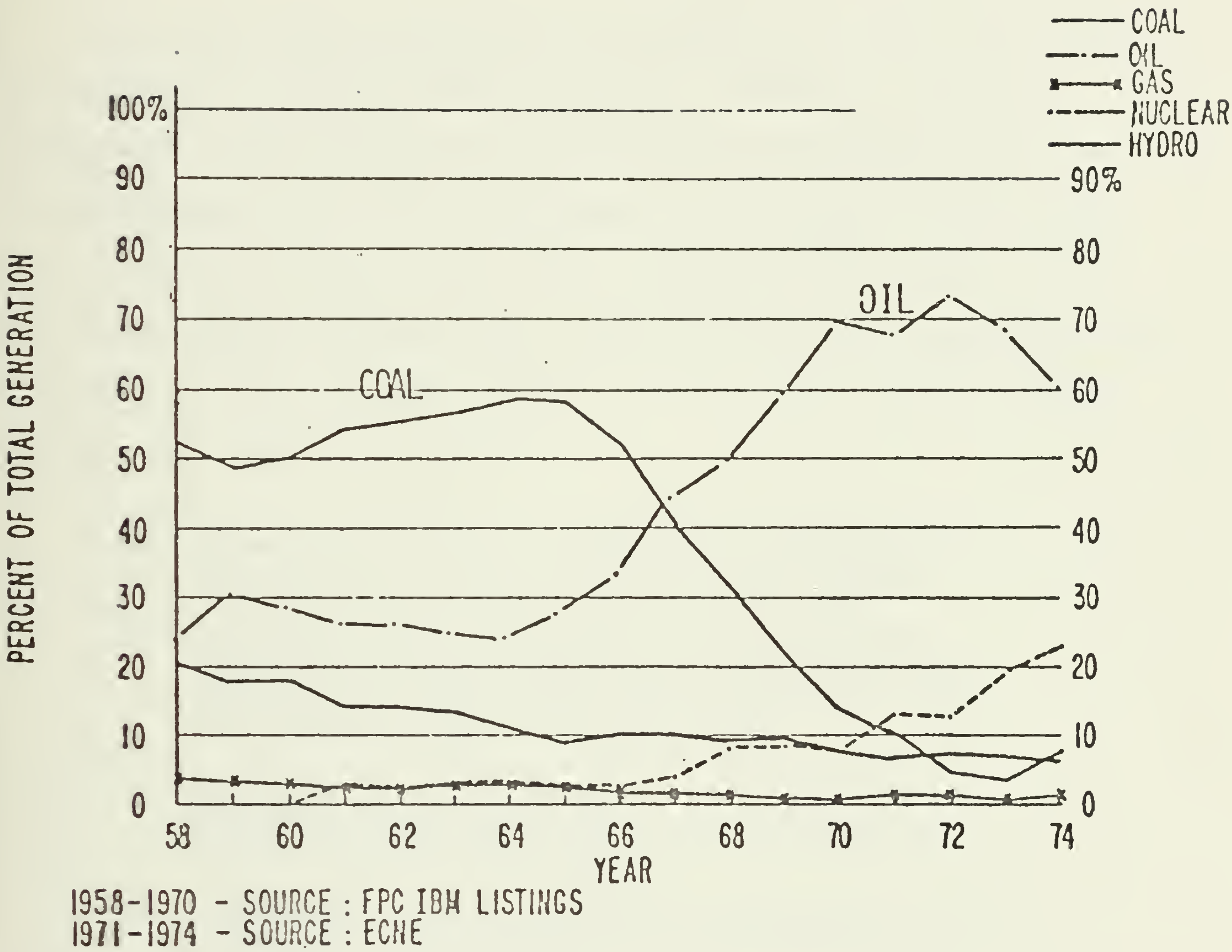
Another alternative would be to import electricity from other regions of the country instead of importing the resources. However, at the present time this would only exacerbate the energy cost disparity, since the transmission of electricity is more expensive per unit of energy than the transportation of an equivalent amount of fuel -- even after accounting for the inefficiencies in converting fuel to electricity [3]. A final alternative would be to institute a policy of energy conservation sufficient to substantially reduce energy expenditures in the region. Such a program would certainly affect life-styles markedly and would require inequitable sacrifices by the New England citizenry unless applied nationwide. Its social and political implications make significant conservation an unlikely possibility, at least in the foreseeable future.

One is led inevitably to conclude that, over the medium term at least, fossil fuel-fired electric power plants will continue to comprise

the largest fraction of total capacity and total electricity generated in the NEPOOL system. The energy cost disparity is certain to persist and the remaining option available to utilities and public policymakers is to mimimize the disparity by insuring that the electricity is generated at the least possible cost.

Because of New England's unfavorable location on the domestic oil and natural gas pipelines, domestic coal and imported residual oil are the principal fossil fuel alternatives. Until 1966, coal was the major source of the electricity generated in the region. Then, from 1966 when import controls were removed on residual oil until 1973, the least expensive, environmentally acceptable fossil fuel delivered to New England was foreign residual oil. As a result, the portion of electricity generated at fuel-powered plants burning coal was reduced from 75 per cent in 1946 and 56 per cent in 1966 to approximately 5 per cent in 1973, while the contribution of residual oil increased from 24 per cent in 1946 to over 72 per cent in 1973. [Fig. 1.1]

Since the 1973 embargo, delivered oil prices have exceeded the coal prices per unit of energy, but New England utilities continue to perceive the total generation costs of oil to be less than that of coal when pollution control costs are factored in (see A.D. Little/S.M. Stoller study, 1975). Thus, in 1976, only one major electric power plant in New England is coal-fired, (the Public Service Company of New Hampshire unit in Bow, New Hampshire), amounting to 2 per cent of NEPOOL's total capacity. Nationwide, coal generates 40 per cent of the electricity. In contrast, foreign residual oil comprises over 85 per cent of the fossil fuel burned for electricity in New England and provides 58 per cent of NEPOOL's total capacity compared with a national average of 15 per cent. Thus, foreign



Source: Mitre Corporation (1976)

Figure 1.1. New England Electric Utilities Fuel Usage (percentage of total power generation)

residual oil would appear to be the fuel of choice in New England in the absence of a governmental mandate to the contrary.

1.2 Federal versus Regional Energy Policies

The current energy situation in New England poses a potential problem in reconciling regional and federal policies. Although a coherent and comprehensive energy policy has not been agreed upon by Congress and the Executive branch of the federal government, the *de facto* national energy policy responds to broader goals than the regional policy. For instance, the Energy Research and Development Administration (ERDA), representing the President has issued several statements defining a set of national energy policy goals. They are as follows:

(1) To maintain the security and policy independence of the nation by minimizing foreign energy imports;

(2) To maintain strong and healthy economy providing adequate employment opportunities and allowing fulfillment of economic aspirations, especially in the less affluent parts of the population;

(3) To provide for future needs so that lifestyles remain a matter of choice and are not limited by the unavailability of energy;

(4) To contribute to world stability through cooperative international efforts in the energy sphere;

(5) To protect and improve the nation's environmental quality by assuring that the preservation of land, water and air resources is given high priority [4].

ERDA has subsequently elaborated on some of these principles to guide actions to achieve these energy goals. The principles relevant to this discussion are the following:

- To provide energy to the American consumer at the lowest possible cost consistent with the need for secure energy supplies;

- To make energy decisions consistent with our overall economic goals;

- To balance environmental goals with energy requirements;

- To seek equity among all our citizens in sharing the benefits and costs of our energy programs [5].

At this level of specificity, the policy is not controversial. It avoids making any tradeoffs and superficially seems to satisfy major interest groups by endorsing low cost energy, a healthy economy, a clean environment, and equity among all citizens. Difficulties for the New England region only begin to occur in the implementation of programs to achieve these diverse goals.

An indication of the ordering of federal priorities vis-a-vis energy policy goals can be obtained by examining the specifics of administration and Congressional programs. The Administration's energy policy views are discussed in "A National Plan for Energy Research, Development and Demonstration", promulgated by ERDA in 1976. In this report it is stated that the nation's energy problem is due to its dependence on diminishing oil and gas resources, especially foreign resources. Thus, it is contended that "actions must be initiated to prepare for a transition . . . to reliance on alternative energy sources, particularly coal and nuclear in the near term" [6]. This emphasis on coal utilization is reflected in ERDA's national ranking of RD & D technology categories where direct coal utilization is listed as a highest priority supply item [Table 1.1] and in the accompanying statement that, "For the near term (now to 1985) and beyond, technology will help to . . .

TABLE 1.1

PROPOSED NATIONAL RANKING OF RD & D TECHNOLOGIES

HIGHEST PRIORITY DEMAND	
Near-term conservation (efficiency) technologies	-- Conservation in buildings & consumer products -- Industrial energy efficiency -- Transportation efficiency -- Waste materials to energy
HIGHEST PRIORITY SUPPLY	
Near-term major energy systems	-- Coal-direct utilization in utility/industry -- Nuclear-converter reactors -- Oil and gas enhanced recovery
New sources of liquids and gases for the mid-term	-- Gaseous and liquid fuels from coal -- Oil shale
"Inexhaustible" sources for the long-term	-- Breeder reactors -- Fusion -- Solar electric
OTHER IMPORTANT TECHNOLOGIES	
Under-used (limited application) mid-term technologies	-- Geothermal -- Solar heating and cooling -- Waste utilization
Technologies supporting intensive electrification	-- Electric conversion efficiency -- Electric power transmission and distribution -- Electric transport -- Energy storage
Technologies being explored for the long-term	-- Fuels from biomass -- Hydrogen in energy systems

*Individual technologies are not ranked within the technology categories

Source: U.S. Energy Research and Development Administration, ERDA-76, 1976

preserve and expand major domestic energy systems: coal, light water reactors, and gas and oil from new sources and by enhanced recovery techniques" [7]. Finally, in the same report ERDA estimates that from 100 to 400 new fossil power plants of 1000 MWe equivalent capacity will potentially be required to satisfy energy demand in the year 2000 [8].

By 1974, Congress had gone beyond expressing policy preferences and granted authority to the Federal Energy Administration (FEA) to order the utilization of coal under provisions of the "Energy Supply and Environmental Coordination Act of 1974" (ESECA) [9]. In Section 2 of ESECA Congress states that the FEA:

> (1) shall by order, prohibit any powerplant . . . from burning natural gas or petroleum products as its primary energy sources;
>
> (2) may require that any powerplant in the early planning process be designed and constructed so as to be capable of using coal as its primary energy source [10].

The issuing of such prohibition and construction orders was contingent upon a determination that a reliable coal supply and adequate coal transportation facilities were available, that the order would not impair the reliability of service, and that the burning of coal was consistent with the purposes of the Act. The purpose of the Act was "to provide for a means to assist in meeting the essential need of the United States for fuels, in a manner which is consistent, to the fullest extent practicable, with existing national commitments to protect and improve the environment" [11].

In April, 1975, in accordance with its ESECA mandate, the FEA released a list of existing gas and oil-fired power plants which in FEA's evaluation could practicably be converted to coal. This candidate list included 159 power plants at 81 generating sites nationwide of which 27 units at 13

sites with a total capacity of 3,327 megawatts (MWe) were located in New England [Table 1.2]. After studying the feasibility of conversion at each of the candidate plants, orders prohibiting the use of oil and gas were issued in July, 1975, to 74 plants at 32 sites including two units at the Schiller generating station in New Hampshire. As of this writing the order to burn coal at Schiller was still being contested by the Public Service Company of New Hampshire and the FEA was preparing to issue prohibition orders to 11 other units in New England by June, 1977 [12].

The current ESECA authority expires on January 1, 1979. However, legislation has already been introduced in the Senate by Senators Randolph, Jackson and Magnusson which would extend and broaden the ESECA authority. Entitled the "National Petroleum and Natural Gas Conservation and Coal Substitution Act," [13] this legislation would require that:

(1) new electric power plant and major industrial installations which become operational after January 1, 1979, and which utilize fossil energy resources as boiler fuel be capable of utilizing coal as their primary energy source, in conformance with applicable environmental requirements;

(2) by January 1, 1980, existing power plants and major industrial installations which utilize fossil energy resources as boiler fuel must acquire the capability to the maximum extent practicable, to utilize coal as their primary energy source in conformance with applicable environmental requirements [14].

Clearly there exists at the federal level substantial governmental support for a policy of increased coal utilization and it is apparent that electric utilities will be strongly encouraged, perhaps ordered, to burn coal instead of oil and natural gas. In contrast, the essence of regional, or more accurately, of New England states' energy policy as expressed by Mr. Paul Levy, Deputy Director of the Massachusetts

TABLE 1.2

FEDERAL ENERGY ADMINISTRATION LIST OF NEW ENGLAND POWER PLANTS CAPABLE OF CONVERTING TO COAL

PLANT	UNIT #	CAPACITY (MWe)	UTILITY
Brayton Point	1, 2, 3	1,162	New England Power Co.
Mt. Tom	1	136	Holyoke Water & Power Co.
Somerset	7, 8	194	Montaup Electric Co.
W. Springfield	2, 3	164	Western Mass. Electric Co.
Schiller	4, 5	100	Public Service Co. of N.H.
South Street Station	121, 122	104	Narragansett Electric Co.
Montville	5	75	Connecticut Light & Power Co.
Mason	3, 4	69	Central Maine Power Co.
Devon	3, 7, 8	273	Connecticut Light & Power Co.
Middletown	1, 2, 3	422	Hartford Electric Light Co.
Norwalk Harbor	1, 2	326	Connecticut Light & Power Co.
Salem Harbor	1, 2, 3	275	New England Power Co.
Kendall Square	3	27	Cambridge Electric Light Co.
	27 Units	3,327 MWe	

Source: Federal Energy Administration, Implementing Coal Utilization Provisions of ESECA, April 1975.

Energy Policy Office, is simply to minimize the rate of electricity cost increases in order to maintain and attract investment to the region [15]. As previously discussed, residual oil appears to be the fuel of choice. The question which must be addressed is whether a coal utilization policy is consistent with the energy policy objectives of New England.

1.3 Statement of Purpose

In light of a possible federal mandatory coal utilization policy, the purpose of this thesis is to conduct an initial multi-objective public policy analysis of coal utilization for electric power generation in New England to provide a basis for answering two fundamental policy questions:

(1) Is a policy of coal utilization economically and/or environmentally desirable for New England?

(2) What structural changes, if any, would cause a regional coal utilization policy to satisfy regional objectives?

The analysis is to be conducted from the perspective of public policy-makers in the region. The dimensions of the analysis will be economic and environmental and the output will be (a) the busbar cost of electricity and, (b) environmental air quality. Implicit in the analysis is the judgment that these two criteria will be the principal determinants of policy.

In addition to answering the policy questions, the objectives of the analysis are to: (1) identify the important and the unimportant variables involved in the coal utilization issue; (2) identify the impact of regulatory policies on coal utilization; (3) identify the major impacts of a coal utilization policy on larger issues for New England, and (4) develop a reasonable framework for the further analysis of the issue.

Without positive action on national energy policy issues by the various governmental entities in the New England region, de facto energy policies will be imposed on the New England citizenry regardless of their best interests because either: (1) federal energy policies will prevail despite regional interests, or (2) organized private concerns (e.g. utilities, consumer groups, or environmental groups) will successfully stall the federal process in the courts or through administrative procedures for their own purposes, again despite the interests of the entire region. Thus, the underlying presumption of this thesis is that state governments in New England, or in any other region of the U.S., should actively pursue the implementation of federal energy policies consistent with the interests of their state and region. In the instances when federal policies are in conflict with regional interests and objectives, state governments and regional representatives have an obligation to attempt to modify those federal policies.

FOOTNOTES Chapter 1

1. Robert Cooke, "N.E. Power Costs Highest in Nation -- by Fifty Two Per Cent," Boston Globe, May 20, 1976, p. 31.

2. This may change if coal deposits in the Narragansett Basin of Massachusetts and Rhode Island prove to be worthwhile mining. This is not likely to be the case in the near future (see Robert Cooke, "R.I. Coal Samples Much Richer Than Expected," Boston Globe, Sept. 23, 1976, p. 42).

3. H.C. Hottel and J.B. Howard, New Energy Technology (Cambridge, Mass.: The MIT Press, 1971), p. 46.

4. U.S. Energy Research and Development Administration, A National Plan for Energy Research, Development and Demonstration, ERDA-48 (Washington: U.S. Government Printing Office, June 28, 1975), p. s-1.

5. U.S. Energy Research and Development Administration, A National Plan for Energy Research, Development, and Demonstration, ERDA-76 (Washington: U.S. Government Printing Office, April 15, 1976), p. vii.

6. Ibid., p. 2.

7. Ibid., p. 28.

8. Ibid., p. 29.

9. Public Law 93-319, 93rd Congress, H.R. 14368, June 22, 1974.

10. Ibid., Section 2(b) (1).

11. Ibid., Section 1(b).

12. Jerry Ackerman, "Eleven N.E. Generating Plants May Switch From Oil to Coal," Boston Globe, Oct. 15, 1976, p. 15.

13. Senate Bill S. 1777, introduced May 20, 1975.

14. Ibid.

15. Interview with Paul Levy, Deputy Director, Massachusetts Energy Policy Office, Boston, Massachusetts, April 15, 1976.

CHAPTER 2. FRAMEWORK FOR ANALYSIS

2.1. Perspective and Scope

Meaningful discussion of the issue of coal utilization in New England requires placing the issue in its proper perspective. It represents, of course, one small portion of the overall question of energy policy in New England which in turn is a small component of national energy policy. But as such, it does have important implications for the nation's security, international trade and relations, employment, and land preservation. On a regional level it also has implications for capital investment, jobs, environmental quality, human health and land use. In short, as an energy issue its effects are wide-ranging and far more significant than simply the contribution of the cost of the electricity generated to the gross regional and national products. More will be said about this aspect of coal utilization in a later chapter.

Ideally, for policymaking purposes, an analysis of coal utilization would also be broad in its scope. It would consider a wide range of policy options including alternative technologies for coal utilization, the construction of new and the conversion of existing power plants, and various plant capacities and locations. It would evaluate the impact of these options on the cost of electricity for the system of which they would be a part and it would evaluate the overall economic impact on the region. Likewise, a comprehensive analysis of the environmental impact of coal utilization would consider both local and regional social costs of coal mining, transportation, storage, air pollution, disposal of wastes, and the associated land use.

Out of necessity, however, the perspective and scope of this thesis must be considerably narrower. Thus, the quantitative analysis presented

here will evaluate the addition of one new pulverized coal-fired electric power plant in Massachusetts to begin operation in 1985. The economic analysis will be limited to estimating a busbar cost of electricity for this plant. When appropriately discounted such cost could be compared with current costs. The environmental analysis will be restricted to a consideration of air pollution from coal combustion, its control and its costs. This restriction is based on the presumption that air pollution represents the most significant environmental impact of coal utilization both in terms of its overall effects and the cost of control. Thus, air pollution is likely to be the controlling environmental factor in determining the environmental <u>and</u> economic acceptability of coal utilization. Pollution control technologies examined will include only existing technologies which have been operated at least at the prototype plant level so that substantiated data on process cost and effectiveness are available. Air quality and air pollution costs will be estimated only in the vicinity of the proposed plant.

Though limited in scope, this analysis will provide a benchmark in the form of a typical, conventional coal-fired power plant at a New England location, using 1976 state-of-the-technology pollution control devices, against which other fuels, other technologies and other scenarios can be measured.

2.2 Criteria for Analysis

As stated previously, the central question of this thesis is whether a policy of coal utilization for electricity generation is desirable for New England. Since the point of view of the question is that of public policymakers in the region, it is regional costs and benefits which are to

be evaluated. The evaluation criterion must be relevant to New England. As a first approximation, a reasonable criterion would be whether coal utilization is consistent with the energy and environmental objectives of the region.

In order to obtain a state perspective, the energy and environmental objectives of Massachusetts were sought in an interview with Mr. Paul Levy, Deputy Director of the Massachusetts Energy Policy Office [16]. According to Mr. Levy, the state's overriding objective is to minimize the rate of energy and electricity cost increases in order to improve the investment possibilities of New England. To this end, it is desirable to keep fuel costs as low as possible and to slow down the growth of electric power systems within the state. In the area of environmental quality, the near term objective is to meet existing standards at the least possible cost. Over the longer term, the state may seek changes to the environmental standards if new standards could adequately protect the environment at a lesser economic cost. When specifically queried as to whether insuring the security of supply of energy resources to the region was an objective, Mr. Levy answered in effect that energy supply and allocation was a federal responsibility, therefore security of supply was not a state objective. In the broad view, the use of domestic energy resources is preferred, but he felt that even the security of domestic supplies was uncertain. If there were to be a supply problem, New England would somehow be taken care of by the federal government.

A disturbing aspect underlying these state objectives is the limited time horizon of their vision. Mr. Levy indicated that his time horizons corresponded to the time frame of his office which was four years and is now two years (the terminus being the Massachusetts gubernatorial election

in 1978). Admittedly, time horizons of this order are to be expected from any elected or appointed official, but that does not alter the fact that it results in a significantly different perception of energy and environmental issues than one which extends say 20 to 40 years. Such short time horizons strongly imply that politicians and appointed policymakers have very high social rates of discount, higher perhaps than private industry's discount rate, at a time when many would argue that the social rate of discount <u>ought</u> to be lower than the private rate, and at a time when the social rate of discount for some energy and environmental issues appears to approach zero [17]. One might reasonably ask how a four year time horizon can adequately cope with the current situation in which the construction of a single energy facility may take ten years or more.

Short time horizons in Massachusetts affect policy objectives in important ways. Since the primary concern is for the health and attractiveness of the economy in the near term, overwhelming emphasis is placed on minimizing economic costs in the near term. Neglected in this view are considerations of environmental quality and public health beyond what is required to meet federally established standards. For example, unusually high ambient pollutant concentrations would probably be acceptable if the federal ambient standards were met, despite possible chronic effects. Or, the emission of potentially hazardous pollutants from a process would probably be permitted if no federal standards were applicable to that pollutant. Similarly neglected by the short term view are long term economic considerations. It is possible that what costs least in the short term may cost most in the long term. A longer time horizon might include an objective which, like an insurance policy, requires somewhat higher costs now in exchange for a degree of security at some later time. To wit, from a long term view,

current use of a fuel costlier than imported residual oil might be justified if its supply were uninterruptable in the future. Concern about the inadequacy of existing objectives noted, this analysis proposes an alternative set of policy objectives. They will be used as the criteria by which to evaluate coal utilization in New England. These regional energy and environmental objectives are as follows:

(1) To minimize consumer energy costs;

(2) To minimize to the greatest practicable extent, environmental and human health impacts from energy usage;

(3) To maximize, at a reasonable cost, the security of supply of energy resources to New England.

Obviously, trade-offs must be made between these objectives and will be discussed subsequently. The question which must be asked now about these objectives is, with what is coal utilization to be compared? Coal is a potential replacement for both nuclear and oil-fired power plants. However, as recent studies have shown, coal is unlikely to be competitive with nuclear as a base-load alternative [18]. If, for some reason, nuclear power ceases to be an alternative, then coal would have to be compared with oil as a base-load plant. More likely, coal will be an alternative, perhaps a mandated one, for intermediate and peak-load fossil-fired plants in New England. Here, too, oil would be the principal competitor. Thus, the extent to which coal utilization meets the policy objectives will be compared with imported residual oil.

2.3 Methodology

The study methodology will consist of two primary components; first, environmental quality analysis and second, economic analysis. The

environmental analysis will include identification of the significant pollutants resulting from coal combustion, identification of the available pollution control technologies, and estimation of pollution control process efficiency and cost. With this data and the use of an atmospheric pollutant dispersion model, curves relating ambient air quality to the cost of achieving that quality can be developed.

The approach to the economic analysis is to estimate, for a given plant configuration, a busbar cost of electricity. Two types of costs will be useful for analysis: an annual cost of electricity per kilowatt-hour for the initial years of plant operation, and a levelized cost of electricity per kilowatt-hour over the design lifetime of the plant. To arrive at these costs, four cost components must be estimated: (1) power plant capital costs exclusive of pollution control equipment but including interest during construction; (2) operation and maintenance costs including the cost of coal waste disposal; (3) fuel costs including the cost of coal transportation and handling, and (4) capital, operation and maintenance costs associated with pollution control.

Upon completing the environmental and economic analysis, coal utilization will then be examined in terms of the policy objectives previously discussed. Critical questions to be addressed which will assist in this analysis are the following:

(1) Can a coal-fired electric power plant in New England satisfy applicable air quality regulations at an economic cost comparable to projected costs for oil-fired generation?

(2) If coal-fired generation is more expensive, are pollution control costs a critical factor in the competitiveness of coal with oil? If so, what level of air quality can be achieved at a cost comparable to oil generation?

(3) If all air quality regulations are met, how do coal and oil-fired generation compare in terms of their public health effects?

(4) If coal-fired generation is more expensive than oil, could it be justified as a means of securing an uninterruptable supply of energy resources to New England?

2.4 Analysis Scenario

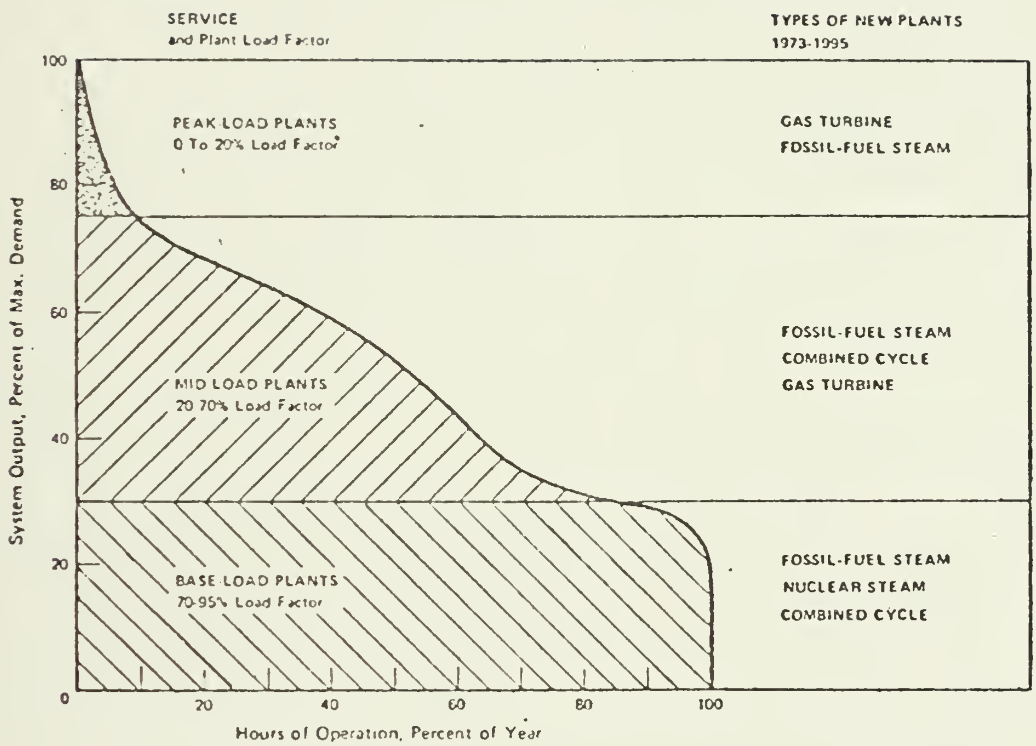
The basic scenario to be evaluated is summarized in Table 2.1. A hypothetical coal-fired electric power plant is to begin construction in 1978 and operation in 1985. Its nominal lifetime will be 30 years. The plant is to be located near Boston, Massachusetts, and for purposes of the air quality analysis the specific plant site will be assumed to be Salem Harbor, Massachusetts. This is not an unreasonable assumption. Until sometime in 1976, the New England Electric System was considering the addition of an 800 MWe power plant at Salem Harbor to begin operation in 1980 [19]. Even though this planned capacity addition is no longer deemed necessary, the Salem Harbor site remains available for further system expansion.

Three different plant capacities and load factors will be evaluated. The 1000 MWe plant will be a base-load plant with a mature load factor of 75 per cent [20]. The 500 MWe will be operated as an intermediate-load plant and the 200 MWe plant will be operated as a peak-load plant. Their assumed load factors are typical of utility power plant utilization as depicted in Figure 2.1. By considering these different capacities and load factors, coal utilization will be evaluated over its range of possible use. In addition, potential economies of scale and the significance of plant load factors in the cost of electricity will be high-lighted.

TABLE 2.1

SUMMARY OF ANALYSIS SCENARIO

PLANT TYPE:	New, coal-fired		
LOCATION:	Salem Harbor, Massachusetts		
BEGIN CONSTRUCTION:	1978		
BEGIN OPERATION:	1985		
NOMINAL LIFETIME:	30 years		
PLANT CAPACITY (MWe):	1000	500	200
MATURE LOAD FACTOR:	75%	50%	20%
HEAT RATE (w/o SO_2 removal, in BTU/kWh):	8700	9000	9300
THERMAL EFFICIENCY:	39%	38%	37%
BOILER TYPE:	Pulverized coal, dry bottom, tangentially-fired		
STACK HEIGHT (feet):	800	800	400
COOLING SYSTEM:	Natural draft, salt water, cooling tower		



Source: D.W. Locklin, et al., Power Plant Utilization of Coal, 1974, p. 19.

Figure 2.1. Load Curve of Typical Utility Electrical Generating System

The boiler to be considered will be a pulverized coal, dry bottom, tangentially-fired boiler. This is a well established technology which also has the advantage of relatively low nitrogen oxide (NO_x) emissions [21]. The assumed heat rates are representative of heat rates currently achievable in new plants in the absence of sulfur oxide removal systems [22].

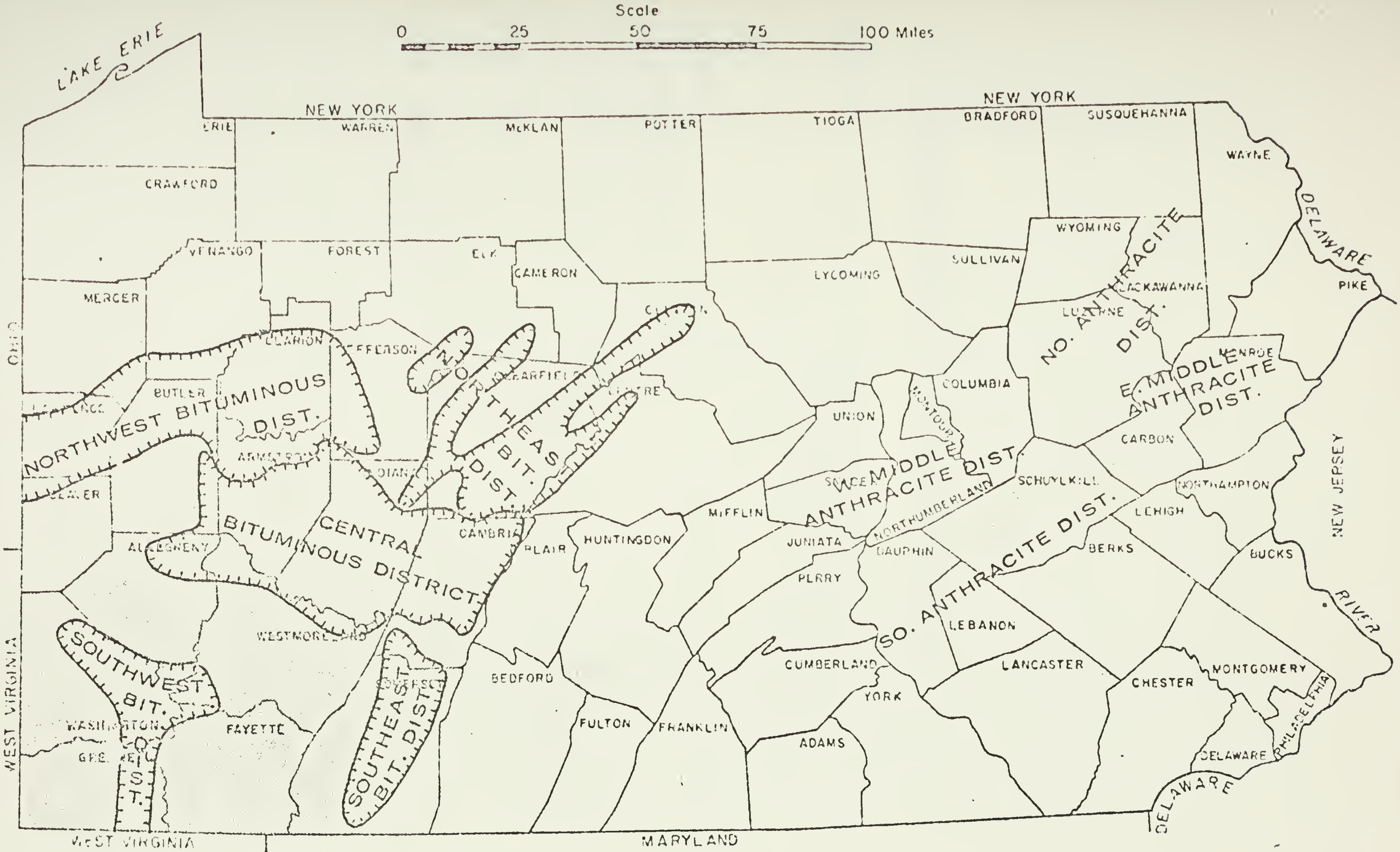
A critical parameter in the ambient air quality calculations will be the smoke stack height. The higher the stack, the lower will be ground level ambient pollution concentrations. But, stack height is limited by technological and economic considerations. Unless otherwise stated, a stack height of 800 feet will be assumed for the 1000 and 500 MWe plants. This is typical of chimneys being currently constructed for large electric power plants [23]. For the 200 MWe plant a shorter stack height of 400 feet will be assumed.

The power plant will use a natural draft, salt water, cooling tower system. Though the Salem Harbor site is located on the ocean, two considerations discourage the use of a once-through cooling system. First, one objective of the Federal Water Pollution Control Act Amendments of 1972 is to eliminate the discharge of pollutants, including heat, into navigable waters by 1985 [24]. It would not be feasible to eliminate all thermal discharges to navigable waters in this case, but the use of cooling towers would lower thermal discharges significantly. Second, the Region I Environmental Protection Agency in Boston has recently disapproved the once-through cooling system proposed at the Seabrook, New Hampshire, nuclear power plant, claiming it would have an adverse affect on marine life (Region I, U.S. Environmental Protection Agency, Permit Application NH 0020338, Initial Decision, November 9, 1976). The EPA strongly recommended the use of cooling towers. Thus, in light of the regulatory

environment, the use of cooling towers is a reasonable condition to impose on the proposed plant. Natural draft cooling towers are generally agreed to be the least costly cooling alternative over the life of the plant [25].

The coal to be burned at the power plant will be assumed to be bituminous coal from a dedicated underground mine in the Upper Freeport Seam, Westmoreland County, Pennsylvania [Figure 2.2]. There are several reasons for making this assumption. First, coal District 1 where the Freeport Seam is located has historically supplied much of the coal used by New England utilities [26]. Second, coal fields in western Pennsylvania are closer to Boston than virtually all other developed bituminous coal fields in the United States, thus minimizing coal transportation costs. Third, since the only large volume of coal currently being transported to New England for utility use originates in Westmoreland County, current unit train tariffs are available from there. Nearly all other unit train tariffs were discontinued to New England several years ago. A typical proximate analysis of Upper Freeport coal is listed in Table 2.2 [27]. These values will be used throughout the remainder of this analysis as the average parameters for the coal combusted in the power plants.

Figure 2.2. Principal Coal Fields in Pennsylvania



Source: 1975 Keystone Coal Industry Manual, p. 608.

TABLE 2.2

PROXIMATE ANALYSIS OF UPPER FREEPORT SEAM COAL

ORIGIN:	Upper Freeport Seam Westmoreland County, Pennsylvania Underground mined, 4-6 foot seam
TYPE:	Bituminous
MOISTURE:	2.5
VOLATILE MATTER (%):	25.5
FIXED CARBON (%):	60.0
ASH (%):	9.0 (Maximum allowed by state regulations)
SULFUR (%):	3.5
Btu/lb:	12,500
FUSION TEMPERATURE (°F)	1,960 - 2,910

FOOTNOTES Chapter 2

16. Interview with Paul Levy, Deputy Director, Massachusetts Energy Policy Office, Boston, Massachusetts, April 18, 1976.

17. The social rate of discount is the rate by which future societal benefits and costs are discounted, or made equivalent to, present benefits and costs. Benefits and costs in future years are usually thought to be worth less than present benefits and costs. For many persons the issue of radioactive waste disposal has a time horizon of 250,000 years implying a discount rate of virtually zero.

18. Arthur D. Little, Inc., and S.M. Stoller Corp., Economic Comparison of Base-Load Generation Alternatives for New England Electric, (Cambridge, Massachusetts: Arthur D. Little, Inc., March, 1975).

19. New England Power Planning, New England Load and Capacity Report: 1974-1985, (West Springfield, Massachusetts: New England Power Planning, April, 1975).

20. Arthur D. Little, Inc., and S.M. Stoller Corp., Economic Comparison, p. 66.

21. Crawford, Manny, Bartok, and Hall, "Control of SO_2 and NO_x Emissions," American Institute of Chemical Engineering Symposium Series, #148 (1975), p. 83.

22. G.G. McGlamery, et al., Detailed Costs Estimates for Advanced Effluent Desulfurization Processes, (Washington, D.C.: U.S. Environmental Protection Agency, 1975), p. 19.

23. "The Building of Tall Stacks," Environmental Science and Technology, June, 1975, p. 522.

24. "Federal Water Pollution Act Amendments of 1972," Section 101.

25. "The Growing Role of Natural Draft Cooling Towers in U.S. Power Plants," Power Engineering, June 1976, p. 60.

26. Richard L. Gordon, U.S. Coal and the Electric Power Industry, (Baltimore: The Johns Hopkins University Press, 1975), p. 78.

27. Keystone Coal Industry Manual (New York: Mining Informational Services, 1975), p. 612.

CHAPTER 3. ENVIRONMENTAL QUALITY ANALYSIS OF COAL UTILIZATION: AIR QUALITY

As previously discussed, the environmental analysis in this thesis will be limited to a consideration of the air pollution resulting from coal combustion -- the presumption being that air pollution is likely to be the controlling environmental factor in the environmental and economic acceptability of coal utilization. The analysis will additionally be restricted to the consideration of air pollution within a 70 kilometer -- about 40 mile -- radius around the plant site. There are two reasons for this. First, the atmospheric dispersion model to be used in determining ambient atmospheric pollutant concentrations is limited in its application to a distance of 70 to 100 km. from the pollution source. Second, such a restriction should still provide the policymaker with useful information since it is expected that the maximum ambient pollutant concentrations will occur well within this radius. Beyond this radius the pollutant concentrations due to the plant in question will be very small. In short, it is assumed that the most significant impact of air pollution from a single power plant is likely to occur within a 70 km. radius of the plant.

The issue of possible global climactic effects from carbon dioxide and particulate loading of the atmosphere is a generic issue involving the world-wide combustion of fossil fuels. As such, it is an issue the scope of which extends considerably beyond the realm of the policymaker in the region. Thus, it will not be addressed in this thesis.

The approach in this chapter will be, first, to define the atmospheric pollutant emission inventory; second, to evaluate air pollution control technologies and costs; and, third, to calculate the ambient air quality

in the vicinity of the power plant as a result of coal combustion.

3.1 Atmospheric Pollutants From Coal Combustion

3.1.1 Atmospheric Pollutant Emission Inventory

The atmospheric pollutant emission inventory was calculated for each of the three power plant capacities assuming steady-state operation at 100 per cent of the nominal power rating. The quantities of coal required given this condition are specified in Table 3.1. No allowance was made for operation of the plant at power above its rated capacity.

In Table 3.2 are listed the pollutants emitted in the flue gas of a coal-fired boiler for which emission factors have been estimated by the U.S. Department of Health, Education and Welfare and by the Environmental Protection Agency. These emission factors are applicable for bituminous coal of approximately 13,000 Btu/lb combusted in a dry-bottom pulverized coal boiler (without pollution control equipment) having a heat input greater than 10^6 Btu/hr [28]. The pollutant emission rates for each pollutant are also compiled in Table 3.2.

The emission rates for particulates, sulfur oxides (SO_x) and nitrogen oxide (NO_x) during uncontrolled combustion are several orders of magnitude larger than the emission rates for the other pollutants. Thus, these would appear to be the pollutants (of those emitted in the flue gas) which may have a significant impact on the air quality in the region. This conclusion is supported in part by comparing the uncontrolled emissions from the 1000 MWe coal-fired plant with the total emissions of the same pollutants in the metropolitan Boston area [Table 3.3]. Only particulate, SO_x and NO_x emissions would be increased significantly. The power plant's contribution

TABLE 3.1

HEAT INPUT AND COAL CONSUMPTION AT 100 PER CENT OF RATED POWER

	1000 MWe	500 MWe	200 MWe
HEAT RATE (Btu/kwh)	8700	9000	9300
HEAT INPUT @ 100% Power (Btu/hr)	8.7×10^9	4.5×10^9	1.86×10^9
COAL HEATING VALUE (Btu/lb)	12,500	12,500	12,500
COAL INPUT REQUIRED			
lb/hr	696,000	360,000	149,000
ton/hr	348.0	180.0	74.4
ton/day	8352	4320	1786

TABLE 3.2

ATMOSPHERIC POLLUTANT EMISSION INVENTORY, EMISSION FACTORS, AND EMISSION RATES FROM TANGENTIALLY FIRED PULVERIZED COAL BOILER

POLLUTANT	EMISSION FACTOR (lb/ton coal burned)	EMISSION RATES (UNCONTROLLED) 1000 MWe	500 MWe	200 MWe
PARTICULATES	17 A[a]	6.12 lb/MBtu 26.6 ton/hr 6709 g/sec	6.12 13.8 3470	6.12 5.69 1434
SULFUR OXIDES	38 S[b]	5.32 lb/MBtu 23.1 ton/hr 5838 g/sec	5.32 12.0 3016	5.32 5.0 1247
NITROGEN OXIDES	18	0.72 lb/MBtu 3.13 ton/hr 789 g/sec	0.72 1.62 408	0.72 0.67 169
CARBON MONOXIDE	0.5	0.02 lb/MBtu 0.087 ton/hr 22.0 g/sec	0.02 0.045 11.3	0.02 0.019 4.7
HYDROCARBONS (CH_4)	0.3	0.012 lb/MBtu 0.052 ton/hr 13.2 g/sec	0.012 0.027 6.8	0.012 0.011 2.8
ALDEHYDES (HCHO)	0.005	2×10^{-4} lb/MBtu 0.22 g/sec	2×10^{-4} 0.11	2×10^{-4} 0.05
POLYNUCLEAR HYDROCARBONS	5.4×10^{-5}	2.2×10^{-6} lb/MBtu 0.002 g/sec	2.2×10^{-6} 0.001	2.2×10^{-6} 5×10^{-4}

a The factor A is the coal ash content in per cent; e.g., if ash is 9% by weight, A = 9.

b The factor S is the sulfur content of the fuel in per cent.

Source: U.S. Department of Health, Education and Welfare, pub. no. AP-24, 33, and 42.

TABLE 3.3

COMPARATIVE POLLUTANT EMISSIONS FROM A 1000 MWe COAL-FIRED PLANT AND TOTAL EMISSIONS FOR THE BOSTON METROPOLITAN AREA

POLLUTANTS	TOTAL BOSTON EMISSIONS[a] (10^3 ton/yr)	1000 MWe COAL-FIRED EMISSIONS[b] (10^3 ton/yr)	% INCREASE IN TOTAL EMISSIONS
PARTICULATES	82	175	213
SULFUR OXIDES	424	152	35.8
NITROGEN OXIDES	168	20.6	12.2
CARBON MONOXIDE	921	0.57	0.06
HYDROCARBONS	87	0.34	0.4

a 1967-1968 data for standard metropolitan statistical area (SMSA) of Boston; the SMSA encompasses 1,280 square miles and population of 2,700,000 as of 1968.

b. Assumes a 75% load factor, and no pollution control.

Source: Air Quality Criteria for Carbon Monoxide, AP-62, National Air Pollution Control Administration, March 1970.

to total carbon monoxide and hydrocarbon emission is minimal, which is not surprising since these pollutants originate primarily from vehicular sources.

Though total aldehyde and polynuclear hydrocarbon emissions are not available for metropolitan Boston, these pollutants will also be neglected in this analysis. Aldehydes, which are the product of incomplete hydrocarbon combustion, will not be considered because the major source of aldehydes is automobile exhaust and because its biological effects begin to occur at concentrations which are an order of magnitude larger than the concentrations at which SO_x causes biological effects [29]. Since SO_x emissions are some four orders of magnitude larger when uncontrolled and about three orders of magnitude larger if controlled than aldehyde emissions, aldehydes are unlikely to create a biological hazard unless ambient sulfur oxide concentrations far exceed acceptable limits. Polynuclear hydrocarbons (also known as polycyclic organic material), on the other hand, are known to be carcinogenic and the emission of even very small quantities to the environment must be of concern to public policymakers. However, because of very high operating temperatures, coal combustion in large power plants is not a significant contributor to total polynuclear hydrocarbon (PNH) emissions. For instance, it has been estimated that in 1967, coal-fired electric generation in the U.S. accounted for 0.6 tons annually of benzo-(a)-pyrene ($C_{20}H_{12}$) emissions (one of several types of PNH emitted during coal combustion) compared with nationwide total emissions of 481 tons per year [30]. Furthermore, at heat rates being considered, the PNH emission rates of oil and coal-fired power plants are of the same order of magnitude [31]. Since this is ultimately a comparative analysis of coal with oil, polynuclear hydrocarbon emissions can be reasonably discounted as a significant factor in evaluating the environmental acceptability of coal _vis-a-vis_ residual oil.

An additional category of pollutant emissions not included in the above inventory is heavy metal emissions. Heavy metals occur in trace quantities in coal and are of two types: barium, lead, manganese, mercury, nickel, selenium, and zinc, for example, are toxic or carcinogenic; radium, strontium, thorium, and uranium are radioactive. At present, there is very limited information available concerning the quantities of the various trace elements in coal, their post-combustion fate, or their possible control technologies. Joensuu [32] found an average mercury content of 3.3 parts per million for 36 American coals. He has also estimated that worldwide, 3000 tons of mercury per year are released to the environment by the burning of coal. This is compared to an estimated upper limit of 230 tons per year released to the environment naturally due to chemical weathering and approximately 10,000 tons per year of industrially produced mercury [33]. Other researchers have found poor collection of selenium by electrostatic precipitators and that as much as 90 per cent of the mercury escapes collection in the flue gas because of its high volatility [34]. Martin, Howard and Oakley [35] have reported measurements which indicate that the release of radium and thorium from a 1000 MWe coal-fired plant burning coal of 9 per cent ash and operating with a particulate cleaning efficiency of 97.5 results in local radiation exposure levels about 400 times greater than those of a pressurized water reactor. (Such radiation levels, however, do not apparently constitute a significant health hazard.)

In short, the social and environmental costs of heavy metal emissions could potentially be very high, but there is clearly insufficient data to make a reasonable estimate of those costs at this time. It is known that the heavy metal emissions are very small in quantity. Also, residual oil combustion emits heavy metals, albeit in smaller amounts than coal, so that

their emission is not unique to coal combustion [36]. Thus, it will be assumed that to a first approximation, in comparison with the very large emissions of particulates, SO_x and NO_x, consideration of heavy metal emissions from coal can be deleted from this analysis without substantially altering the results. This is not an unreasonable position for a state policymaker to take. Heavy metal emissions are a generic issue applicable to coal combustion nationwide and need to be resolved as such. Without additional information, a Massachusetts policymaker, for instance, would probably not be justified in permitting or rejecting coal utilization solely on the basis of heavy metal emissions. However, heavy metal emissions must be categorized as an uncertain element in the analysis which will require more data to resolve and which should be considered as a caveat in the final analysis.

Hence, particulates, sulfur oxides and nitrogen oxides are the significant atmospheric pollutants of coal for which emission control technologies and costs will be evaluated in this analysis.

3.1.2 Secondary Pollutants -- Acid Sulfate Aerosols

Secondary pollutants are products of chemical reactions that occur amongst pollutants emitted in the power plant plume, but they are not an immediate product of the combustion process and thus are not included in the pollutant emission inventory. One such pollutant of particular concern is acid-sulfate aerosols. These are formed when the SO_2 emitted from a fossil-fired plant is oxidized in the atmosphere and transformed into sulfate salts and sulfate acids, including sulfuric acid (H_2SO_4). Acid-sulfate aerosols are fine particulates which have a long atmospheric residence time and are capable of penetrating deep into the human respiratory

tract adversely affecting human health. The also may be washed out of the atmosphere by precipitation resulting in "acid rain" which is harmful to vegetation and marine life.

Since acid-sulfates are not emitted in the flue gas stream, they are not subject to direct control at the power plant, nor have any sulfate standards been established by regulatory agencies. Nonetheless, it is known that the rate of acid-sulfate formation is a function of the quantity of SO_2 and fine particulate emissions. Thus, any policy decision on the environmental acceptability of coal utilization must consider the contribution of pollutant emission to the formation of acid-sulfates. This topic will be discussed in greater detail in Chapter 5.

3.2 Air Quality Regulations Applicable to Coal Combustion

The first policy question to be addressed is whether coal combustion can satisfy applicable air quality regulations at a reasonable cost. There are three categories of air quality regulations to which coal combustion in Massachusetts must conform: (1) federal and state ambient air quality standards (AAQS); (2) federal New Source Performance Standards (NSPS); and (3) Massachusetts air pollution control regulations, including emissions limitations and fuel quality standards. The federal ambient air quality standards for particulates, and SO_x and NO_x were also adopted by Massachusetts and are listed in Table 3.4. The primary standards are defined as the maximum permissible atmospheric pollutant concentrations which, "allowing for an adequate margin of safety, are requisite to protect the public health" [37]. Secondary standards are sufficiently stringent to "protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air" [38]. The range of ambient pollutant concentration within a 70 km. radius of the proposed plant in Salem, Massachusetts, during 1975 and as estimated for 1985 is also listed in Table 3.4. The 1985 estimates were made by the Massachusetts Department of Environmental Quality Engineering based on pollution sources projected for that year. Isopleths of annual SO_2 and particulate concentrations estimated for Massachusetts for 1975 and 1985 are presented in Appendix G.

The proposed new coal-fired power plant must also conform to the federal New Source Performance Standards which were promulgated by the Environmental Protection Agency as directed by the Clean Air Act. The NSPS are standards which establish a maximum emission of pollutants per unit of heat input. The criterion for setting these standards was that they reflect "the degree of

TABLE 3.4

FEDERAL AND MASSACHUSETTS PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS

POLLUTANT	AIR QUALITY STANDARD ($\mu g/m^3$) PRIMARY	SECONDARY	RANGE OF AIR QUALITY* IN 70 KM. RADIUS OF PLANT ($\mu g/m^3$) 1975	1985 (est.)
Particulates				
Annual mean	75	60	40-73	40-74
Max. 24 hr. concentration	260	150	159-264	--
Sulfur Oxides				
Annual mean	80 (0.03 ppm)	60 (0.02 ppm)	5-44	5-50
Max. 24 hr. concentration	365 (0.14 ppm)	260 (0.1 ppm)	92-181	--
Max. 3 hr. concentration	--	1300 (0.5 ppm)	--	--
Nitrogen Dioxides				
Annual mean	100 (0.05 ppm)	100	N/A - 102	--

* The first number is the pollutant level at Salem, the second is the level at Kenmore Square in Boston.

Source: U.S. Environmental Protection Agency, Region I, 1975 Annual Report on Air Quality in New England, (Boston, Massachusetts: U.S. Environmental Protection Agency, April, 1976)

emission limitations achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator of the EPA determines has been adequately demonstrated" [39]. New Source Performance Standards for particulates, SO_x and NO_x have been promulgated for fossil-fuel fired steam generating units of more than 250 million Btu per hour heat input. These are applicable to each of three power plant capacities considered here and are specified in Table 3.5.

Also under the provisions of the Clean Air Act, each state was required to adopt a plan which provides for the implementation, maintenance, and enforcement of the primary ambient standards. Massachusetts adopted the regulations described in Table 3.6 for Boston. Notice that the particulate emission regulation is more stringent than the federal NSPS unless sulfur oxide control equipment is used at the same time. The sulfur regulation applies to the sulfur content in the fuel and is actually less stringent than the federal standard which applies to sulfur dioxide (by weight, two grams of sulfur are equivalent to one gram of SO_2).

In all cases of conflict between regulations, the more stringent regulation is applicable. Thus, the composite emission limitations listed in Table 3.7 must be achieved under current regulations. The analysis that follows will consider the technologies available and costs of meeting these standards and regulations.

Finally, the Administration of the Environmental Protection Agency has issued regulations designed to "prevent the significant deterioration of air quality in any portion of any State where the existing air quality is better than one or more of the secondary standards" (39 FR 42514). The

TABLE 3.5

FEDERAL NEW SOURCE PERFORMANCE STANDARDS --
COAL-FIRED STEAM GENERATION OF MORE THAN 250 MBtu/hr

POLLUTANT	MAXIMUM PERMISSIBLE EMISSION (lb/MBtu)	AVERAGING TIMES
PARTICULATES	0.10	2 hours
SULFUR DIOXIDE	1.20	2 hours
NITROGEN OXIDES	0.70	2 hours

TABLE 3.6

MASSACHUSETTS AIR POLLUTION CONTROL REGULATIONS FOR THE METROPOLITAN BOSTON AIR POLLUTION CONTROL DISTRICT

POLLUTANT	REGULATION	COMMENTS
PARTICULATES	0.05 lb/MBtu Ash content of fuel not to exceed 9 per cent by dry weight.	Heat input > 250 MBtu/hr. An emission rate of 0.10 lb/MBtu will be allowed if equipment designed to control or reduce SO_2 at the same time is used.
SULFUR	Sulfur content of fuel not to exceed 1.21 lb/MBtu (equivalent to 1.5% sulfur coal of 25 MBtu/ton) or emissions having no greater pollution effect than this (equivalent to 2.42 lb SO_2/MBtu).	This regulation is in effect until July 1, 1977. It may then revert to 0.55 lb/MBtu.

TABLE 3.7

EMISSION LIMITATIONS APPLICABLE TO A NEW COAL-FIRED POWER PLANT LOCATED IN BOSTON, MASSACHUSETTS

POLLUTANT	EMISSION LIMITATION (lb/MBtu)	COMMENTS
PARTICULATES	0.05	No SO_x removal
	0.10	With SO_x removal
SULFUR OXIDES	1.20	
NITROGEN OXIDES	0.70	

regulations require the establishment of "classes" of allowable incremental increases in total suspended particulates (TSP) and sulfur dioxide. Class I applies to areas in which practically any change in air quality would be considered significant; Class II applies to areas in which deterioration normally accompanying moderate well-controlled growth would be considered insignificant; and Class III applies to those areas in which deterioration up to the national ambient standards would be considered insignificant. Boston and all of Massachusetts are considered Class II areas.

In reviewing the acceptability of a new pollutant source, the significant deterioration regulations impose two additional requirements. First, instead of meeting only the applicable emission limitations, sources must also meet an emission limitation which is consistent with the use of the best available control technology. This is determined on a case-by-case basis. Second, the effect on ambient air quality of the source in conjunction with the effects of growth and reduction in emissions of other sources must not violate the following air quality increments applicable to Class II areas:

		Air Quality Increment ($\mu g/m^3$)
Particulates:	Annual mean	10
	24 hr. max.	50
Sulfur Dioxide:	Annual mean	15
	24 hr. max.	100
	3 hr. max.	700

Thus, the proposed power plants must be also analyzed in terms of the significant deterioration regulations.

3.3 Air Pollution Control Technologies and Costs

3.3.1 Particulate Control

Particulate emission control is a mature technology which has been extant for 50 years in the case of electrostatic precipitation. The control processes are well understood, their efficacy satisfies environmental regulations, and electric utilities have apparently accepted them as a necessary capital and operating expense. This suggests, from the policy-maker's perspective, that with respect to particulate emissions, economic and environmental objectives are approximately in balance and that it is reasonable to expect the new power plants to conform to existing particulate regulations. This does not necessarily imply that emissions which satisfy regulations are acceptable, but it does establish the maximum acceptable emissions.

Particulate collection is necessary regardless of the SO_2 control process employed; however, a wet flue gas desulfurization (FGD) system does have the capability of scrubbing particulates and SO_2 simultaneously. This one-stage process is potentially less expensive in terms of capital and operating costs than a two-stage process with separate particulate and SO_2 collection. Nonetheless, a two-stage process with particulate collection first, followed by SO_2 removal, will be assumed in this analysis. Two factors influenced this selection. First, in some FGD processes, the presence of fly ash in the scrubber can decrease its availability and efficiency. The increased solids load may aggravate scaling on the scrubber surfaces necessitating more frequent maintenance and it may increase sulfite oxidation reducing the reactant available for precipitating out SO_2. As a result, one industry source reports a strong trend amongst utilities toward

dealing with particulate collection separately from SO_2 removal [40]. Second, having a separate particulate collection system would enable the plant to continue to operate and meet particulate emission standards, if regulations permit, during periods when the FGD system is unavailable. Such arrangement would increase the overall plant availability and flexibility in comparison with a single-stage process.

In order to operate without a FGD system, the particulate control system must be capable of conforming to the state emission limitation of 0.05 lb/MBtu. This requires a collection efficiency of 99.2% by weight for a 9% ash coal. There are three particulate collection processes currently available which are capable of achieving collection efficiencies in excess of 99 per cent: fabric filters, venturi scrubbers, and electrostatic precipitators. Fabric filters are used in a baghouse configuration. Baghouses are structures arranged around the smokestack base containing woven bags which function as particulate filters for the flue gas which is forced through them [Figure 3.1]. Particulates cling to the bag fabric and are periodically removed by gravity or mechanical means. Until recently, fabric filters were not acceptable for power plant application because of the high temperatures of the flue gas. The development of polyfluoroethylene (teflon) and fiberglass bags capable of tolerating temperatures of 550 - 600°F has partially overcome this problem. Fabric filters have collection efficiencies greater than 99 per cent and reportedly as high as 99.5 to 99.9 per cent [41], and perform effectively down to 0.1 micron particle size [42].

Venturi scrubbers operate as shown in Figure 3.2. Centrifugal and inertial forces used to separate particles from the gas stream are supplemented by liquid scrubbing of the gas which absorbs and flushes away the particles. Venturi scrubbers are classified by the amount of energy used which is

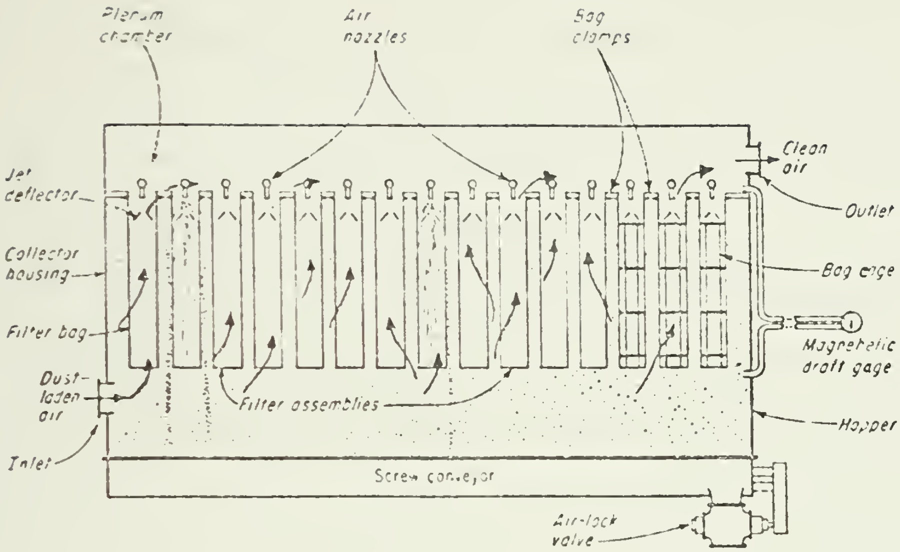


FIGURE 3.1 SCHEMATIC VIEW of FABRIC FILTER BAGHOUSE

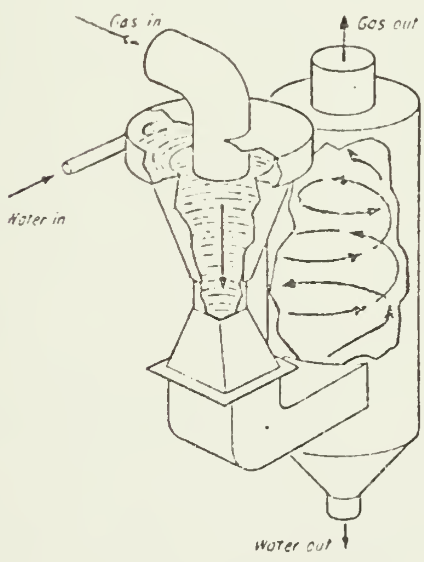


FIGURE 3.2 SCHEMATIC VIEW of VENTURI PARTICLE SCRUBBER

proportional to the turbulence with which the scrubbing liquid is mixed with the flue gas. Medium-energy scrubbers typically have 98 per cent particulate collection efficiencies and are effective down to about 1 micron size; high-energy scrubbers are more efficient, 98 to 99.5 per cent, on particles of approximately 0.1 to 0.5 microns [43].

Electrostatic precipitators (ESPs) operate by electrically charging particles in the flue gas as they pass through a high-voltage, direct current corona. The corona is established between an electrode maintained at high voltage and grounded collecting plates [Figure 3.3]. Particulate matter passing through the corona is subjected to an intense bombardment of negative ions flowing from the electrode to the collecting plates and becomes charged. They then migrate toward and are deposited on the grounded collecting plates. The collecting plates are periodically vibrated, or rapped, causing the particulate to fall by gravity into a storage hopper. ESPs typically operate with collection efficiencies from 99 to 99.8 per cent for particles less than 0.1 microns in size [44].

The criteria for selection of a specific particulate control technology include collection efficiency, capital costs, and operating costs. All three technologies are capable of achieving the 99.2 per cent efficiencies required to meet state emission limitations (assuming the scrubber is of a high energy type). However, as indicated in Figure 3.4, venturi scrubbers and ESPs are capable of collecting smaller size particles than are fabric filters. This is important since submicron particles are the most damaging to the environment and human health. In addition, fabric filters are largely untested on large coal-fired power plants and baghouse configurations are generally conceded to require the largest capital investment of the three types of systems [45]. This narrows the selection to venturi scrubbers and

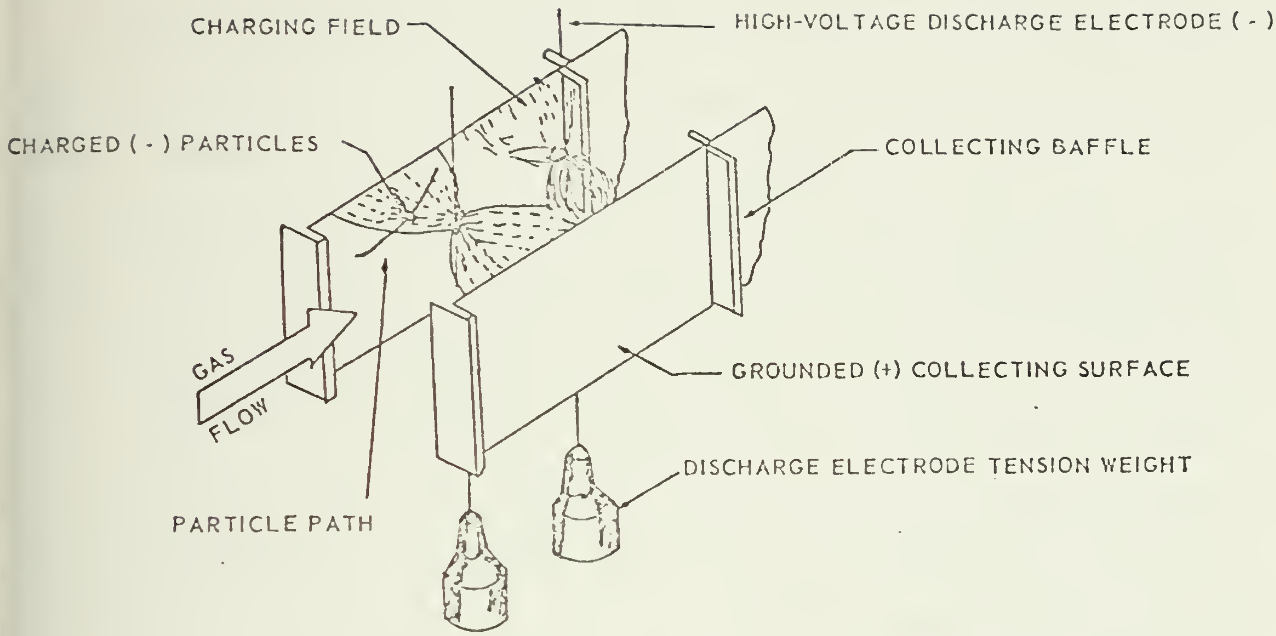


FIGURE 3.3 SCHEMATIC VIEW of PARALLEL PLATE ELECTROSTATIC PRECIPITATOR

FIGURE 3.4 PARTICLE SIZE - EFFECTIVENESS of PARTICULATE COLLECTION PROCESSES

ESPs.

Detailed capital and operating cost data available in the literature for particulate collection systems are uniformly poor, perhaps because it is a mature technology and costs are well known to those who would use it. The best data was found in three studies of FGD costs (McGlamery, et al., 1975; PEDCo, 1975; U.S. Dept. of Commerce, 1975 [46]) and computerized cost estimates for steam-electric power plants (CONCEPT -- see Section 4.1) prepared by Oak Ridge National Laboratory. These estimates are displayed in Figure 3.5. The data for new coal-fired plants are normalized to 1975 dollars but are somewhat inhomogeneous due to differences in collection efficiencies, assumptions affecting flue gas flow rates, and plant location. Nonetheless, the respective capital costs of scrubbers and precipitators do not appear to be very different [47]. Precipitators, however, have an advantage over venturi scrubbers in terms of operating and maintenance costs. If energy requirements can be used as a proxy for operating expenses, scrubbers require from 1 to 2 per cent of the plant's gross energy input whereas ESPs require less than 0.5 per cent of the energy input [48]. At least one utility industry source does not recommend the use of high-energy venturi scrubbers on coal-fired power plants because of high operating costs [49]. On balance, precipitators may have a small advantage over venturi scrubbers in terms of annualized costs.

An intangible factor influencing the selection from the utility's perspective may be the 50 years of experience in operating ESPs. The technology is mature and well understood. Indeed, a steam station design survey conducted in 1976 [50] found ESPs to be the overwhelming choice as the particulate control technology to be installed on coal-fired power plants which are to begin operation between 1976 and 1984. The distribution was as follows:

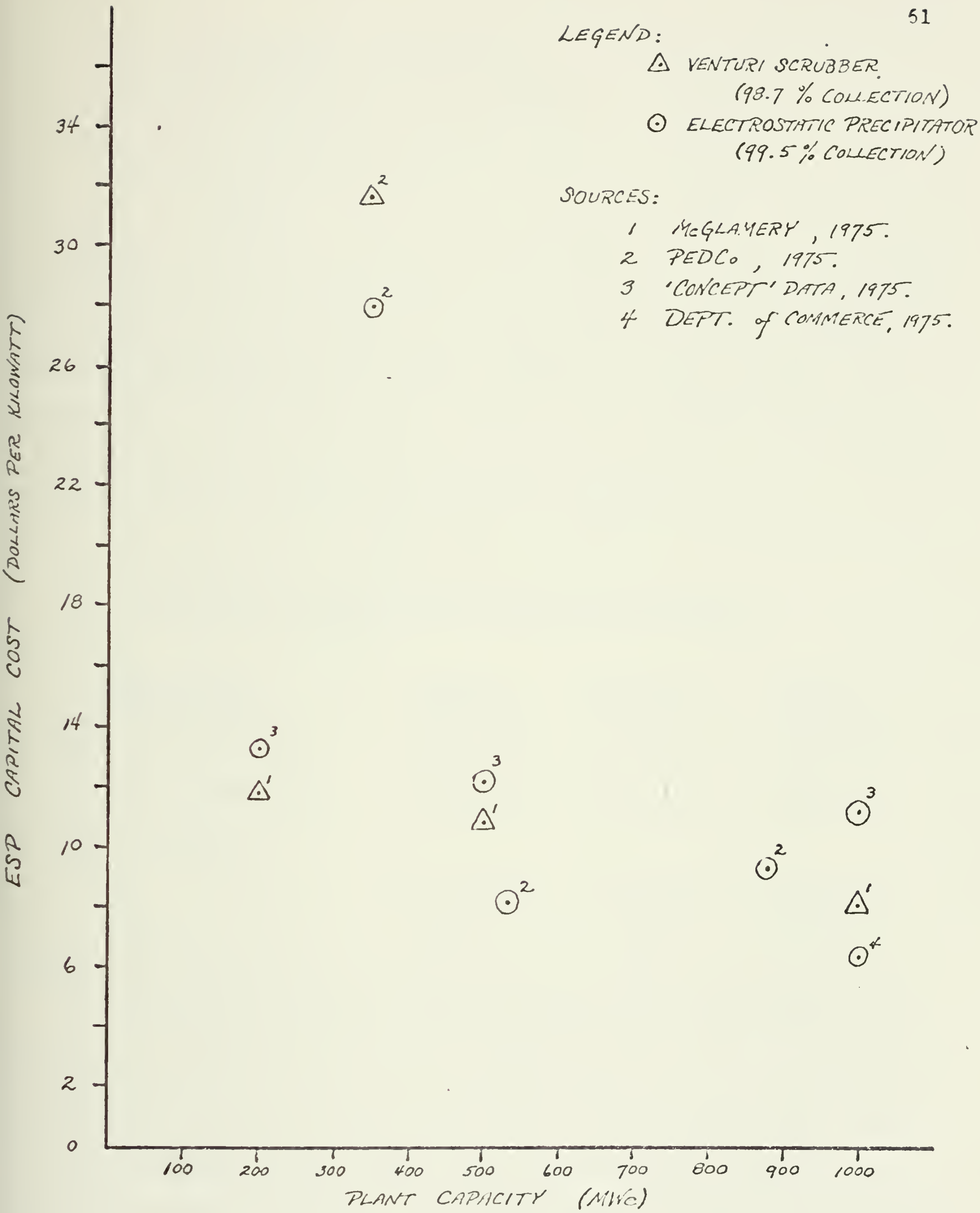


FIGURE 3.5 ELECTROSTATIC PRECIPITATOR CAPITAL COST ESTIMATES (NEW COAL-FIRED; 1975 $)

Electrostatic precipitators	54 units
ESP combined with wet scrubbers	6 units
Wet scrubbers	2 units
Baghouse	1 unit

Thus, electrostatic precipitators will be assumed to be the particulate control process to be installed in each power plant and will be assumed to have a minimum particulate collection efficiency of 99.5 per cent. The assumed capital costs will be those estimated by the CONCEPT program expressed in 1978 dollars for a Boston, Massachusetts, location.

TABLE 3.8

ELECTROSTATIC PRECIPITATOR CAPITAL COSTS (1978 $)

CAPITAL COSTS	1000 MWe	500 MWe	200 MWe
Direct Investment ($)	8,840,000	4,752,000	2,081,000
Indirect Investment ($)	4,926,000	2,648,000	1,159,000
Total Investment			
($)	13,766,000	7,400,000	3,240,000
($/KW)	13.8	14.8	16.2

The electricity required to operate an ESP is the major component of ESP operating and maintenance costs. Assuming that the power requirements for ESP are 0.5% of power plant capacity and that maintenance costs amount to 3% of the direct investment [51], ESP annual operating and maintenance costs are as shown in Table 3.9. To reference these costs to the beginning of construction in 1978, a general inflation rate of 6 per cent per year will be assumed from 1975 to 1978.

The cost components which have been discussed can be translated into

TABLE 3.9

ELECTROSTATIC PRECIPITATOR OPERATING AND MAINTENANCE COSTS

		1000 MWe	500 MWe	200 MWe
Load Factor (%)		75	50	20
Annual Electrical Generation (Kwh/yr)		6.57×10^9	2.19×10^9	3.5×10^8
Cost Components	Unit Cost (1975 $)			
Electricity	$0.025/Kwh			
Quantity, KW		5,000	2,500	1,000
Cost, $/yr		821,750	273,937	43,825
Operating Labor	$8.00/man-hr			
Quantity, man/day		.05	.05	.05
Cost, $/yr		3,510	3,510	3,510
Maintenance				
% of Direct Invest.		3	3	3
Cost, $/yr		265,200	142,560	62,430
Total O & M Costs				
1975 $/yr		1,090,460	420,007	109,765
1975 mills/Kwh		0.17	0.19	0.31
1978 $/yr*		1,297,647	499,808	130,620
1978 mills/Kwh*		0.20	0.23	0.37

*Assumes 6% annual inflation 1975 - 1978

annual costs of operation by summing the operating costs and fixed charges. Fixed charges accrue throughout the life of the plant and are independent of plant operation. They include taxes, insurance, depreciation charges, and capital costs due to interest on borrowed funds. Fixed charges are proportional to the capital investment and the constant of proportionality is called the fixed charge rate. It is common practice to use a levelized fixed charge rate which, if kept constant during plant life, would have exactly the same effect as would the time-varying fixed charge rate. The expression for the levelized fixed charge rate is:

$$\phi = \frac{\dfrac{1}{1 - \tau}}{\displaystyle\sum_{i=1}^{30} \frac{1}{(1 + x)^i}} - \frac{\tau d'}{1 - \tau} + \pi$$

where for a typical Massachusetts case, the summation is over years i (1 to ep in this case) and:

τ = overall income tax rate (federal plus state) = 0.5138

d' = fraction of initial investment depreciated for tax purposes per year = 0.033

x = effective discount rate, including taxes (bond fraction = 0.5; stock fraction = 0.5; avg. bond rate = 8%; avg. return on stock = 12%) = 0.0794

π = property taxes and insurance = 0.0297

then the levelized fixed charge rate is:

$\phi = 0.1762$

More will be said about this parameter in Chapter 4. Using this value for the fixed charge rate, the annual costs of ESP operation were calculated and are displayed in Table 3.10.

The selection of an electrostatic precipitator is subject to an important caveat: the coal quality in terms of Btu's/lb, sulfur and ash control

TABLE 3.10

ANNUAL COSTS OF ELECTROSTATIC PRECIPITATOR OPERATION (1978 $)

	1000 MWe	500 MWe	200 MWe
O & M costs, $/yr	1,297,647	499,808	130,620
Fixed charges, $/yr (@ 17.62% of capital investment)	2,431,560	1,303,880	570,888
Total annual cost $/yr	3,729,207	1,803,688	701,508
Total Annual Cost 1978 mills/Kwh	0.57	0.82	2.0

must remain approximately constant or the precipitator's efficiency may be adversely affected. A critical factor in ESP performance is the ash resistivity. The resistivity generally increases as the sulfur to ash ratio decreases if other variables remain constant. As the resistivity increases, collection efficiency decreases because the electric field between the discharge electrode and collecting plate decreases. The use of a low sulfur coal, in conjunction with an ESP designed to collect particulates from high sulfur coal, will result in a decrease in ESP efficiency and potential violations of emission limitations. Therefore, it is important that the utility have a long term contract for a specific quality coal and that state fuel quality regulations remain constant over the life of the plant. Otherwise, significant alteration costs for the ESP system may be incurred at some future time.

A final comment on particulate control is necessary. According to the National Research Council, "tonnage collection figures and weight-removal efficiencies are inadequate to delineate the entire particle-emission problem" [52]. A particle collection efficiency of 99.7% by weight may correspond to a removal of only 30 per cent of all particles by number [53]. The particles which escape collection are the fine particulates (< 3μ in diameter) which only recently have been identified as one of the most important forms of air pollutants. They have a long residence time in the atmosphere, causing their effects to be spread over a large geographical area. Fine particles in size from 0.4μ to 0.8μ are responsible for making the power plant plume highly visible because of their light scattering characteristics. More importantly, fine particulates are a health hazard since, in contrast to coarser particles, they can escape the body's respiratory filters and penetrate deep into the lungs. Contrary to the often

stated position that particles less than 0.3μ enter the respiratory system and are subsequently exhaled, over 50% of the number of particles between 0.01 and 0.1μ that penetrate the pulmonary system will be deposited [54]. The chemical and physical properties of the fine particles can aggravate the health impact. Furthermore, because of their large surface area, some fine particulates have been identified as transport vehicles for gaseous pollutants (absorbed and reacted) and hence produce synergistic effects harmful to human health [55]. However, the health effects of fine particulates are impossible to generalize since the effects are completely dependent on the specific particle's chemical or toxic nature. These characteristics are not capable of being adequately defined at present.

Unfortunately for the policymaker and for the public, the technology for the measurement and the control of fine particulates has not yet been developed. Nor is the extent of the fine particulate impact on public health understood. Undoubtedly, there is a problem, but the tools to evaluate it or control it are not currently available. Again, a lack of information precludes a resolution of the problem. The best the policymaker can probably do is to include fine particulates as a caveat in the final analysis and to highlight them as an area requiring further research, possibly with the assistance of public funds.

3.3.2 Sulfur Oxide Control

There are three basic types of near-term options for the continuous control of sulfur oxide emissions which would be available for application in a power plant to begin construction in 1978. They are:

(1) Flue gas desulfurization;

(2) Low-sulfur coal combustion;

(3) Coal benefication (washing) [56].

Two other types of control are available in the near-term, but they do not satisfy the emission limitations specified in the New Source Performance Standards. The first type is dynamic or intermittent emission controls (also referred to as supplementary control systems). Dynamic controls rely on the dispersion capacity of the atmosphere to meet ambient air quality standards. When meteorological conditions favor the rapid dispersion of pollutants, high SO_2 emissions would be permitted. For instance, a high sulfur coal could be burned without removing SO_2 from the flue gas. When meteorological conditions result in a reduction in the dispersive capacity of the atmosphere, SO_2 emissions would be reduced by switching to a low sulfur fuel, flue gas desulfurization, or by shifting the electrical load to another plant in the same network, but at a location where conditions are more favorable for pollutant dispersion. The second type of control is the use of tall stacks to disperse the pollutants over a large geographical area, thus preventing the occurence of high ground-level concentrations in the vicinity of the plant. If the stack is tall enough, the AAQS can potentially be met without the use of emission reduction systems.

Though acknowledged as the least expensive types of SO_2 emission control systems [57], under current federal regulations neither dynamic controls nor tall stacks are acceptable as the primary method of controlling SO_2 emissions from new sources. Hence, at least in the initial analysis, these options need not be considered by the state policymaker.

3.3.2.1 Flue Gas Desulfurization (SO_2 Scrubbers)

The near-term availability of flue gas desulfurization (FGD) for reliable commercial operation is, in fact, ambiguous. The Environmental Protection Agency has been encouraging the widespread application of FGD systems for the past several years. Their support of FGD is based on the belief that alternative methods of continuous emission reduction are not available in adequate quantities in the near-term [58], and on favorable estimates of FGD process reliability and costs [59]. The electric utilities, on the other hand, are considerably less optimistic about FGD availability. In only three instances through mid-1976 (Cholla, Arizona; Colstrip, Montana; and Paddy's Run, Kentucky) have scrubber installations achieved proven industrial-scale acceptability as defined by the National Academy of Engineering (90% availability on a 100 MWe or larger unit for more than one year) [60]. The three plants which achieved these criteria burned low-sulfur Western coal. The criteria have not been met while burning high-sulfur Eastern coal. In terms of costs, regulatory agencies and scrubber vendors quote considerably lower FGD cost figures than do the utilities [61].

For the purposes of this analysis, reasonably favorable assumptions will be made with respect to flue gas desulfurization systems. To wit, it will be assumed that SO_2 scrubbers will be a demonstrably reliable technology by 1980, in time for installation on the proposed plants, and that scrubber costs will be representative of a "developed" technology. Furthermore, cost estimates from government agencies, scrubber vendors and private consultants will be preferentially used instead of electric utility estimates. Many utility estimates are based on experience from a "first-of-a-kind" installation and are unrepresentatively high. In addition,

because of their comparatively low cost estimates, use of government, vendor and consultant cost estimates will provide the most favorable economic picture for scrubbers. This assumption may prove valuable in the later analysis where any disagreement or uncertainty on scrubber costs will have the single effect of making the costs higher.

There are two basic types of flue gas desulfurization processes as defined by their end products: non-regenerable (throwaway) and regenerable (recovery) processes. In non-regenerable processes, the end product is a sludge which is either deposited in a nearby pond or trucked away to a remote disposal site. Regenerable processes yield a usable product, generally elemental sulfur, but sometimes sulfuric acid or fertilizer-base compounds. Another process division is between wet and dry FGD systems. In a wet system, the reactant is suspended in a liquid slurry, whereas in a dry system, the dry reactant is contacted directly with the flue gas. An inherent advantage of dry systems is that stack-gas reheat is not required. In wet systems, the cooled gas (as a result of passing through the slurry) exiting from the scrubber must be reheated to avoid condensation in the stack and to provide the flue gas with additional bouyancy. These basic process types are summarized in Figure 3.6.

At present, over 50 different flue gas desulfurization processes are technically feasible in that they have demonstrated the ability to remove SO_2 from gas streams. A comprehensive list of these processes is contained in Appendix A. The processes most likely to have commercial application in the near-term must meet the following criteria:

(1) Technical feasibility;

(2) Advanced state of development;

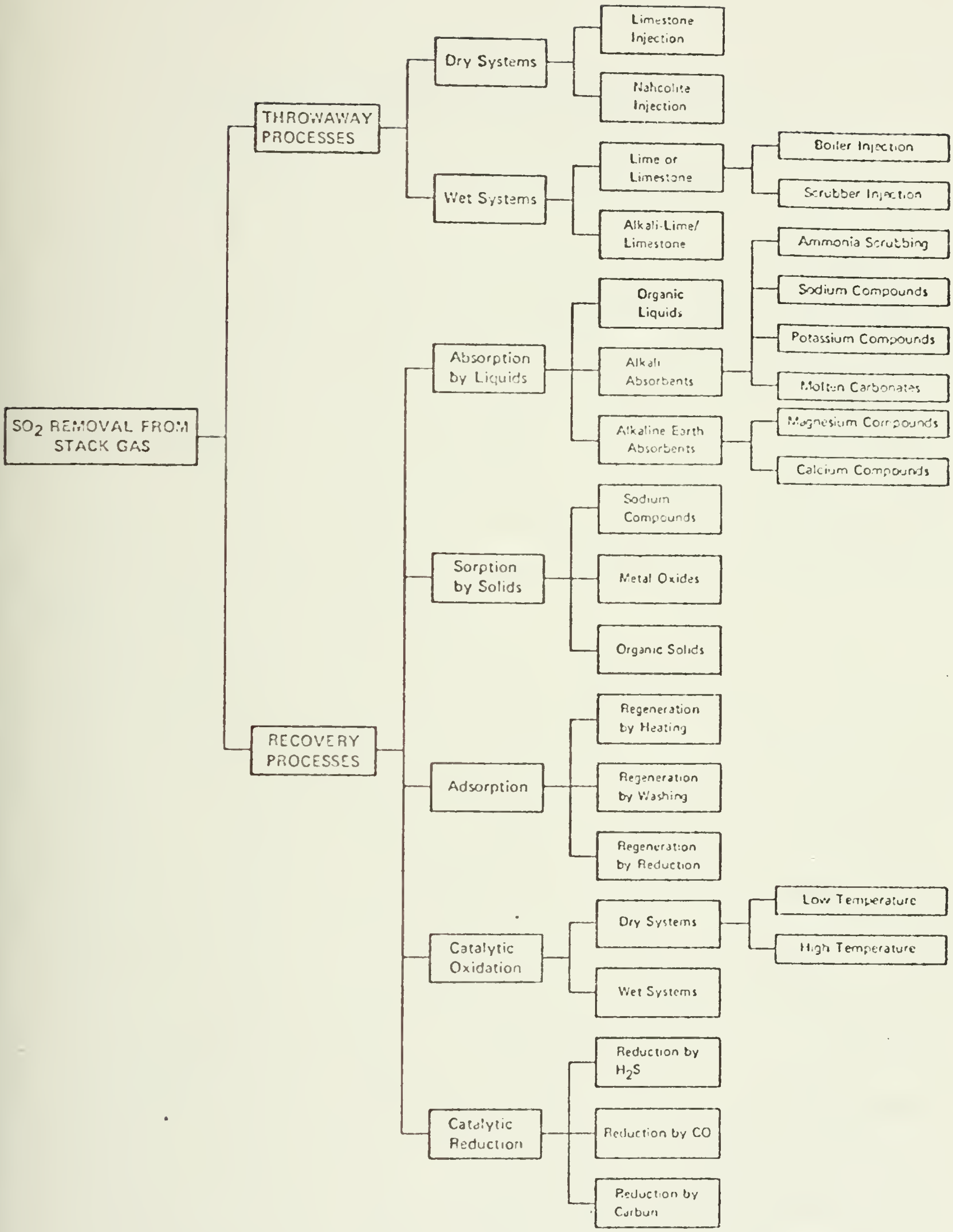


Figure 3.6. Flue Gas Desulfurization Process Types

(3) Electric utility acceptance;

(4) Favorable economic impact;

(5) Marketability of end product in recovery process; environmental impact in throwaway processes;

(6) Possibility of solving process problems.

Based on these criteria and a thorough review of the literature, six processes, as listed in Table 3.11, could potentially be available for installation in the proposed plants. Each of these processes has been operated at least as a prototype or demonstration unit on a coal-fired plant with a capacity in excess of 100 MWe as shown in Table 3.12. It is not reasonable to expect processes in earlier stages of development to be available for installation on a full-scale power plant beginning in 1978 and to provide reliable service thereafter.

It will not be necessary to evaluate the costs for each of the six processes. Rather, two representative processes, a non-regenerable and a regenerable one will be evaluated. The obvious selection for the non-regenerable process is limestone scrubbing (lime scrubbing could have been selected without significantly affecting the analysis). Limestone scrubbing is the most widely used and best understood of the FGD processes. As indicated in Table 3.13, it is the overwhelming choice amongst utilities for installation in new power plant units. The regenerable process to be considered will be the Wellman-Lord/SO_2 reduction process. There are three reasons for this selection. First, there are several detailed cost estimates of this process available. Second, Wellman-Lord is considered an expensive process and thus its evaluation will provide an idea of the range of FGD system costs. And third, it is further developed than most of the regenerable processes and is one of two regenerable processes which has been selected by utilities for

TABLE 3.11

STATUS OF FLUE GAS DESULFURIZATION PROCESSES

PROCESS	TYPE	TYPICAL SO_2 REMOVAL EFFICIENCY, %	END PRODUCT/ WASTE PRODUCT	STAGE OF DEVELOPMENT*
Limestone scrubbing	Nonregenerable	90	Calcium sulfite & calcium sulfate sludge	Commercial
Lime scrubbing	Nonregenerable	92	Calcium sulfite & calcium sulfate sludge	Commercial
Sodium carbonate (single alkali)	Nonregenerable	90	Calcium sulfite & calcium sulfate	Demonstration unit
Magnesium-oxide scrubbing	Regenerable	91	Sulfuric acid or sulfur	Commercial
Catalytic oxidation	Regenerable	85	Sulfuric acid	Commercial
Wellman-Lord SO_2 reduction	Regenerable	90	Sulfur	Demonstration unit

* Stage of development assessed by EPA in Report to Congress on Control of Sulfur Oxides, February, 1975, p. 28 - 29.

TABLE 3.12

FULL-SCALE FLUE GAS DESULFURIZATION INSTALLATIONS ON COAL-FIRED BOILERS IN THE UNITED STATES (START-UP BY 1976)

YEAR OF START-UP	FACILITY	VENDOR	SIZE OF FACILITY (MWe)	COAL SULFUR (%)
LIMESTONE SCRUBBING				
1972	Commonwealth Edison - Will County	B & W	165	2.1
1973	Kansas City P & L - La Cygne	B & W	820	5.2
1973	Arizona Public Service - Cholla 1	Research-Cottrell	125	0.4 - 1.0
1974	Southern Calif. Edison - Mohave	UOP	160	0.5 - 0.8
1975	Detroit Edison - St. Clair	Peabody	180	3.7
1976	Northern States Power - Sherbourne	Comb. Engr.	680	0.8
1976	Central Illinois Light - Duck Creek	Riley-Stoker	100	2.5 - 3.0
1976	Springfield City Utilities - Southwest	UOP	200	3.5
1976	Texas Utilities - Martin Lake 1	Research-Cottrell	793	1.0
LIME SCRUBBING				
1973	Louisville G & E - Paddy's Run	Comb. Engr.	70	3.5 - 4.0
1973	Duquesne Light - Phillips	Chemico	387	1.0 - 2.8
1974	Southern Calif. Edison - Mohave	Searns-Roger	170	0.5 - 0.8
1975	Ohio Edison - Bruce Mansfield	Chemico	825	---
1975	Duquesne Light - Elrama	Chemico	510	1.0 - 2.8
1976	Columbus & Southern Ohio - Conesville 5	UOP	400	4.5
1976	Louisville G & E - Cane Run	American Air Filter	178	3.5
1976	Louisville G & E - Cane Run	Comb. Engr	183	3.5
SODIUM CARBONATE (single alkali)				
1974	Nevada Power - Reid Gardner 1	C.E.A.	125	0.5 - 1.0
1974	Nevada Power - Reid Gardner 2	C.E.A.	125	0.5 - 1.0
1976	Nevada Power - Reid Gardner 3	C.E.A.	125	0.5 - 1.0

MAGNESIUM OXIDE SCRUBBING				
1973	Potomac Electric - Dickerson	Chemico	100	2.0
1975	Philadelphia Electric - Eddystone	United Engr.	120	2.5
CATALYTIC OXIDATION				
1972	Illinois Power - Wood River	Monsanto	110	2.9 - 3.2
WELLMAN-LORD/SO_2 REDUCTION				
1975	Northern Indiana P.S. - D.H. Mitchell	Davy Power Gas	115	3.5

installation on new units as shown in Table 3.13. A process description of the limestone and Wellman-Lord are included in Appendices B and C respectively.

As indicated in Table 3.11, both FGD processes are capable of removing 90% of the SO_2 from the flue gas. In order to meet the New Source Performance Standards, 1.2 pounds of SO_2 emitted per million Btu's, a removal efficiency of only 77.5% is necessary. Thus, cost estimates will be made for both 80 and 90 per cent SO_2 removal efficiencies.

Cost Components of Flue Gas Desulfurization Systems

There are three types of costs to be considered in evaluating a FGD system: capital, operating, and replacement power costs. Capital costs have direct and indirect components. Direct costs are for process equipment, installation, land, and site development. Major process equipment required for regenerable and nonregenerable FGD systems are listed in Table 3.14. Site development includes right-of-way for sludge disposal, site clearing and grading; construction of access roads and walkways; establishment of rail, barge or truck facilities; landscaping; and fencing.

Indirect capital costs include the following major elements:

> Engineering costs, including administrative, process, project and general; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; consultant fees; purchasing; procurement; travel expenses; living expenses; expediting; inspection; safety; communications; modeling; pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services.

> Construction field expense and contractor's fees, including costs for field labor payroll; supervision field office; personnel; construction offices; temporary roadways; railroad trackage; maintenance and weld shop; parking lot; communications; temporary piping; electrical and sanitary

TABLE 3.13

FLUE GAS DESULFURIZATION UNITS PLANNED FOR INSTALLATION ON NEW COAL-FIRED UNITS

YEAR OF START-UP	FACILITY	VENDOR	SIZE OF FACILITY (MWe)	COAL SULFUR (%)
LIMESTONE SCRUBBING				
1978	Alabama Electric - Tombigbee 2	Peabody	225	0.8 - 1.5
1979	Alabama Electric - Tombigbee 3	Peabody	225	0.8 - 1.5
1977	Arizona P.S. - Cholla 2	Research- Cottrell	250	0.4 - 1.0
1977	Indianapolis P & L - Petersburg 3	UOP	530	3.0
1977	S. Miss. Electric - R.D. Morrow 3	Riley-Stokes	180	1.0
1977	Texas Utilities - Martin Lake 2	Research-Cottrell	793	1.0
1978	Texas Utilities - Martin Lake 3	Research-Cottrell	793	1.0
1979	Arizona Electric Power - Apache 2	Research-Cottrell	200	0.8
1979	Arizona Electric Power - Apache 3	Research-Cottrell	205	0.8
1977	S. Carolina P.S. - Winyah 2	B & W	140	1.0
LIME SCRUBBING				
1978	Columbus & S. Ohio - Conesville 6	UOP	400	4.5
1977	Tuah P & L - Huntington 1	Chemico	405	0.5
SODIUM CARBONATE				
1979	Nevada Power - Reid Gardner 4	C.E.A.	125	0.5 - 1.0
WELLMAN-LORD/SO_2 REDUCTION				
1977	P.S. of New Mexico - San Juan 1	Davy Power & Gas	375	0.8
1978	P.S. of New Mexico - San Juan 2	Davy Power & Gas	500	0.8
1980	P.S. of New Mexico - San Juan 3		500	0.8

TABLE 3.14

MAJOR PROCESS EQUIPMENT FOR FGD SYSTEM

EQUIPMENT	DESCRIPTION
Material handling-raw materials	Equipment for the handling and transfer of raw materials includes unloading facilities, conveyors, storage areas and silos, vibrators, atmospheric emission control associated with these facilities, and related accessories.
Feed preparation-raw materials	Equipment for the preparation of raw materials to produce a scrubbing slurry consists of feed weighers, crushers, grinders, classifiers, ball mills, mixing tanks, pumps, agitators, and related accessories.
SO_2 scrubbing	Equipment of a nonregenerative system for scrubbing the SO_2-laden flue gas includes scrubbers, demisters, effluent hold tanks, agitators, circulating pumps, pond water return pumps, and related accessories. In addition, scrubbing equipment for a regenerative system includes convertor, catalyst storage, conveyors, and related accessories.
Flue gas reheat	To increase plume buoyancy and minimize condensation the scrubber exhaust gas is heated from about 125° to 175°F. Equipment required includes an economizer, air/steam or fluid heaters, condensate tanks, pumps, soot blower, and related accessories.
Gas handling	Equipment to handle the boiler flue gas includes booster fans, ductwork, flue gas bypass system, turning vanes, supports, platforms, and related accessories.
Sludge disposal	Nonregenerative FGD systems require a clarifier, pumps, vacuum filtration, sludge fixation equipment, and related accessories.
Utilities	Equipment to supply power to the FGD equipment consists of switch-gear, breakers, transformers, and related accessories.
Cake processing	Equipment for processing the by-prodict of regenerative FGD systems includes a rotary kiln, fluid bed dryer, conveyor, storage silo ($MgSO_3$, etc.),

	vibrator, combustion equipment and oil storage tanks, waste heat boiler, hammer mills, etc. Or, evaporators, crystallizers, strippers, tanks, agitators, pumps, compressors, etc. Or H_2SO_4 abosrber and cooling, mist eliminator, pumps, acid coolers, tanks, etc.
Regeneration	Equipment for regeneration of the scrubber medium of a regenerative system consists of: coke material handling system, storage, weight feeder, conveyor, rotary kiln, fluid bed calciner, dust collector, storage silo (MgO, etc.), vibrator, combustion equipment and oil storage tanks, waste heat boiler, hammer mill, etc. Or, evaporators, crystallizers, strippers, tanks, agitators, pumps, compressors, etc. Or H_2SO_4 absorber and cooling, mist eliminator, pumps, acid coolers, tanks, etc.
Purge treatment	Equipment for the removal of sodium sulfate includes refrigeration, pumps, tanks, crystallizer, centrifuge, dryer, dust collector, conveyors, storage, and related equipment.

Source: PEDCo, Flue Gas Desulfurization Process Cost Assessment, 1975.

facilities; fire, material and medical safety expenses; construction tools and rental equipment; unloading and storage of materials; permits and licenses; taxes; insurance overhead; legal liabilities; field testing of equipment; labor relations.

Contingency costs, including those for malfunctions; premium time for repairs; materials for process; price changes due to inflation; and wage scale increases.

Freight, including delivery costs on process and related equipment shipped F.O.B.

Taxes, including sales, franchise, property and excise taxes.

Spare parts, stock to permit 100 per cent process availability, including pumps, valves, controls, special piping and fitting instruments, spray nozzles, and similar items.

Start-up and modification allowances; including start-up utilities costs; alterations to design equipment.

Interest during construction on borrowed capital.

The percentages of direct capital investment used to estimate these indirect costs are shown in Table 3.15. These factors are based on established methods for estimating indirect investment costs. They agree with the general projected values used in various cost estimating sources as well as in detailed estimates of FGD costs [62]. Slightly lower values for engineering costs and start-up and modification allowance are projected for the nonregenerable process reflecting less complex engineering than associated with the regenerable process.

The major operating and maintenance costs of a FGD system are comprised of the following:

Raw materials, including those required by the FGD process for SO_2 control, make-up for system loss, and chemicals for sludge fixation.

Utilities, including water for slurries, cooling and cleaning; electricity for pumps, fans, valves, lighting, controls, conveyor and mixers; fuel for flue gas reheating; and steam for processing.

Operating labor, including supervisory, skilled, and unskilled

TABLE 3.15

INDIRECT CAPITAL INVESTMENT FACTORS FOR FGD PROCESSES - NEW COAL-FIRED POWER PLANT

NONREGENERABLE PROCESS

INDIRECT COSTS	PERCENTAGE OF DIRECT INVESTMENT 1000 MWe	500 MWe	200 MWe
Engineering costs	8.0	9.0	11.0
Construction field expenses	10.0	11.0	13.0
Contractor's fees	5.0	5.0	7.0
Contingency	9.0	10.0	11.0
Freight	1.0	1.0	1.0
Taxes	1.5	1.5	1.5
Spare parts	0.5	0.5	0.5
TOTAL INDIRECT COSTS AS % OF DIRECT COSTS	35.0	38.0	45.0

*****

Start-up and modification allowances = 8% of direct plus indirect costs
Interest during construction = 8% of direct plus indirect costs

REGENERABLE PROCESS

INDIRECT COSTS	PERCENTAGE OF DIRECT INVESTMENT 1000 MWe	500 MWe	200 MWe
Engineering costs	10.0	11.0	13.0
Construction field expenses	10.0	11.0	13.0
Contractor's fees	5.0	5.0	7.0
Contingency	9.0	10.0	11.0
Freight	1.0	1.0	1.0
Taxes	1.5	1.5	1.5
Spare parts	0.5	0.5	0.5
TOTAL INDIRECT COSTS AS % OF DIRECT COSTS	37.0	40.0	47.0

*****

Start-up and modification allowances = 10% of direct plus indirect costs
Interest during construction = 8% of direct plus indirect costs

labor required to operate, monitor, and control the FGD process.

Maintenance and repairs, consisting of both manpower and materials required to keep the system operating.

Overhead costs for administrative, safety, engineering, legal and medical services; payroll expenses; employee benefits; recreation; and public relations.

Byproduct credits for marketable products from regenerable systems, including sulfuric acid and salt cake (Na_2SO_4) from the Wellman-Lord process.

Table 3.16 provides a compilation of operating cost factors for the non-regenerable and regenerable processes. The sources of these estimates are the same as for the indirect capital cost projections (G.G. McGlamery, et al.; PEDCo-Environmental Specialists, Inc.) with the exception of electricity costs which are estimated as 2.5 cents per kilowatt for Massachusetts in 1975.

There are also energy and replacement capacity costs associated with FGD systems which are frequently not included in FGD cost evaluations. Replacement capacity is the additional generating capacity required to compensate for the power used by the FGD system such that the net generating capacity remains the same. Associated with this power loss is an energy penalty in terms of an increase in the number of Btu's required to produce a kilowatt-hour of electricity. This translates into an increase in the coal input to the boiler. The energy consumed by the FGD system is about equally divided between energy for stack gas reheat and electricity to run the process equipment, including fans to overcome the pressure drop, pumps, conveyors and ball mills. These power losses vary from 2% to 7% of power plant output depending on the system [63]. In this analysis, the FGD power requirements will be those estimated by PEDCo-Environmental, Inc. of 2.7% for both the limestone and Wellman-Lord processes (this does not include the additional energy in the form of process steam required to operate the Wellman-Lord regeneration

TABLE 3.16

OPERATING AND MAINTENANCE COST FACTORS FOR FLUE GAS DESULFURIZATION PROCESSES

COST COMPONENT	UNIT COSTS (1975 $) LIMESTONE NON-REGENERABLE PROCESS	WELLMAN-LORD REGENERABLE PROCESS
RAW MATERIAL		
Limestone	6.00 $/ton	-----
Fixation chemical	2.00 $/ton	-----
Soda ash	-----	55.00 $/ton
UTILITIES		
Electricity	0.025 $/KWh	0.025 $/KWh
Reheat steam	0.76 $/MBtu	0.76 $/MBtu
Process steam	-----	0.76 $/Mgal
Process water	0.018 $/Mgal	0.018 $/Mgal
OPERATING LABOR		
Direct labor	8.00 $/manhr	8.00 $/manhr
Supervisory	15% of direct labor	15% of direct labor
MAINTENANCE		
(% of direct investment)	9 (200 MWe) 8 (500 MWe) 7 (1000 MWe)	7 (200 MWe) 6 (500 MWe) 5 (1000 MWe)
OVERHEAD		
Plant	50% of operating labor and maintenance	
Payroll	20% of operating labor	
BYPRODUCT CREDITS		
Sulfuric acid	-----	20.00 $/ton
Salt cake (Na_2SO_4)	-----	40.00 $/ton

facility which does not result in a capacity derating [64].

There are several methods of determining replacement capacity costs. Since the proposed plants are to be new facilities, a reasonable estimate of these costs is to assume that the capacity is replaced by initially building larger plants such that the net capacities remain 1000 MWe, 500 MWe, and 200 MWe respectively. Then, the capital costs calculated by CONCEPT (see Chapter 4) can be used to estimate the incremental replacement costs. The impact of FGD power requirements on plant parameters are delineated in Table 3.17.

FGD Capital Cost Estimates

Though there are many estimates of FGD costs available in the literature, only a very few provide useful data for this type of analysis. Amongst the data needed in order to establish a basis for comparison are reference dates for cost estimates, explicit assumptions made in the estimates particularly with respect to interest and fixed charge rates, and the relationship between FGD costs and power plant size. Two excellent studies (G.G. McGlamery, et al.; PEDCo-Environmental, Inc; see note 46), both conducted for the EPA in 1975, provide such data and will be the basis for the cost estimates in this analysis. McGlamery, et al., of the Tennessee Valley Authority estimated capital costs for five FGD processes primarily using vendor data and previous purchase experience. PEDCo used a model plant approach for estimating FGD costs. Their report also includes estimates from FGD system manufacturers and costs reported to the Edison Electric Institute in a survey of utilities that are either installing or planning to install FGD systems.

The different cost estimates have been adjusted, where possible, to

TABLE 3.17

FGD REPLACEMENT CAPACITY COSTS AND ENERGY PENALTIES

CAPACITY COSTS	1000 MWe	500 MWe	200 MWe
FGD power losses	2.7	2.7	2.7
Power plant capital costs (1978 $/KW)	425	510	687
Incremental replacement capacity costs (1978 $/KW)	11.5	13.8	18.6
ENERGY PENALTY			
Original heat rate (Btu/KWh)	8700	9000	9300
Heat rate w/ FGD (Btu/KWh)	8934	9243	9550
Coal input w/ FGD (tons/hr)	357	185	76.4

conform to the following conditions:

(1) Costs are adjusted to January, 1975, dollars; Chemical Engineering Plant Cost Index = 180.0;

(2) The FGD system is installed on a new coal-fired power plant;

(3) The system operates with 90% SO_2 removal;

(4) Particulate control costs are not included;

(5) Replacement power costs are not included;

(6) Indirect capital costs are calculated using the factors listed in Table 3.13, including 8% interest during construction;

(7) The process sludge is disposed at an on-site location that is adequate for disposal over the lifetime of the plant. Fly ash disposal costs are not included.

The adjusted capital cost estimates in terms of dollars and dollars per kilowatt for the limestone and Wellman-Lord processes are plotted versus plant size in Figures 3.7 through 3.10.

It is apparent that even these adjusted capital cost estimates vary considerably, by 100 per cent or more in some cases. It is also apparent that the utilities consistently provide the highest estimates and thus establish a reasonable upper limit to FGD costs. However, the utility estimates are not necessarily the "best" estimates since many are applicable to "first-of-a-kind" or early installations of a new technology. This is reflected in the fact that, in the case of limestone slurry systems, the cost per kilowatt is approximately constant for all plant sizes. There is not yet an economy-of-scale evident in the construction of larger installations as is generally the case with engineering systems. Thus, in real dollars, it is reasonable to expect that future FGD installations may be less expensive in terms of cost per unit size as the technology matures

Figure 3.7. Adjusted Total Capital Cost Estimates For Limestone Slurry Scrubbing System (1975 $)

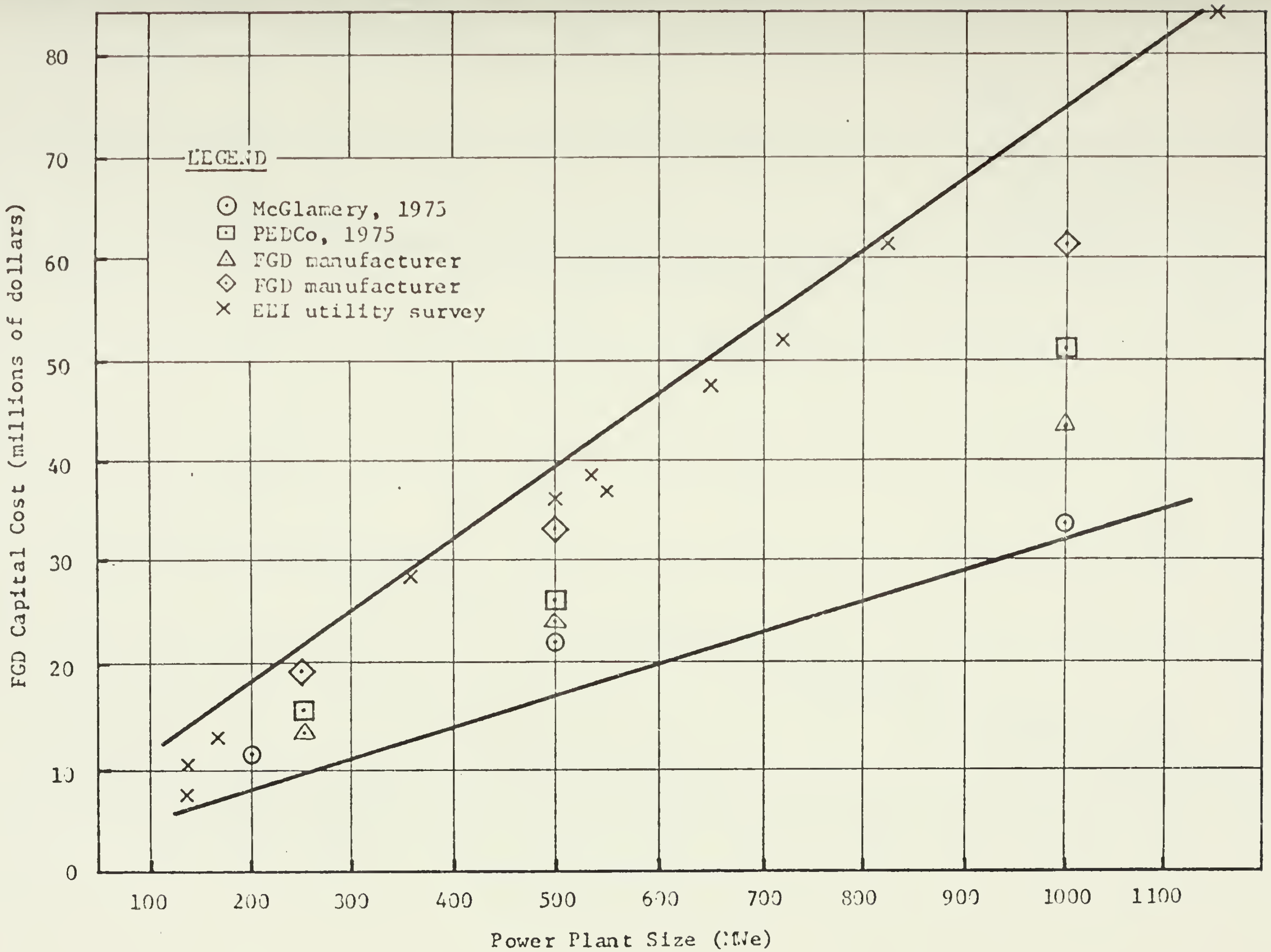


Figure 3.8. Adjusted Unit Capital Cost Estimates For Limestone Slurry Scrubbing System (1975 $)

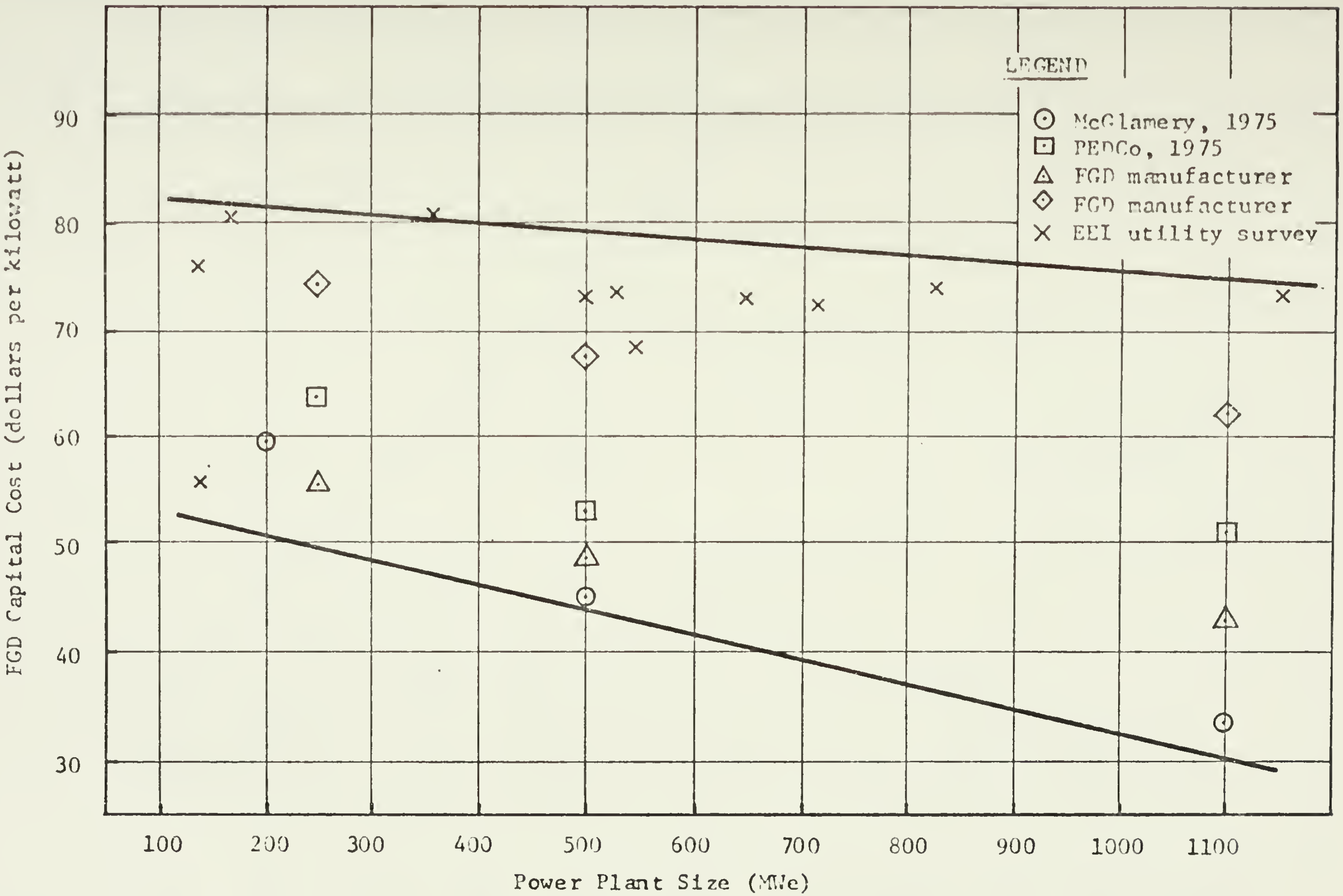


Figure 3.9. Adjusted Total Capital Cost Estimates For Wellman-Lord Scrubbing System (1975 $)

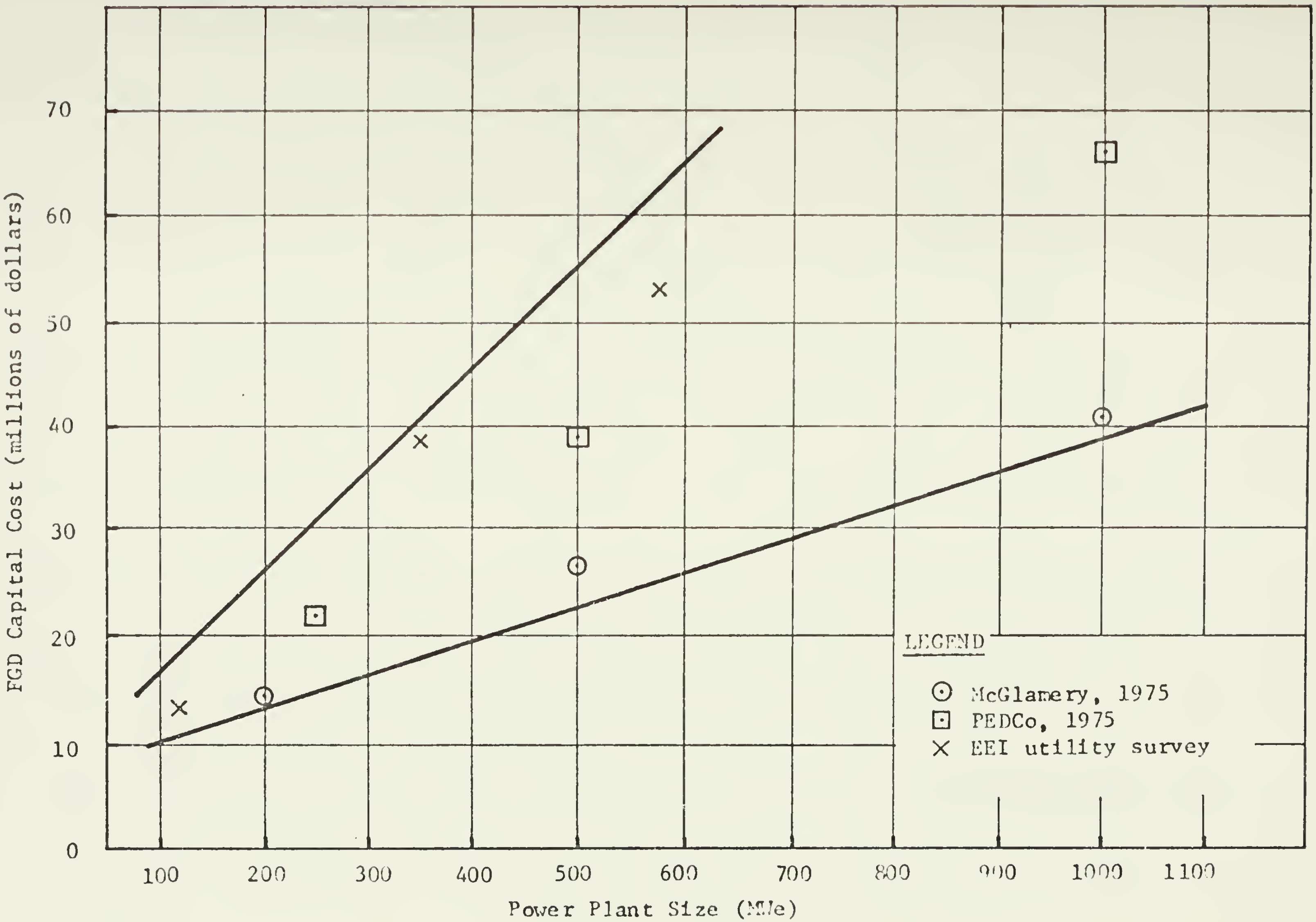
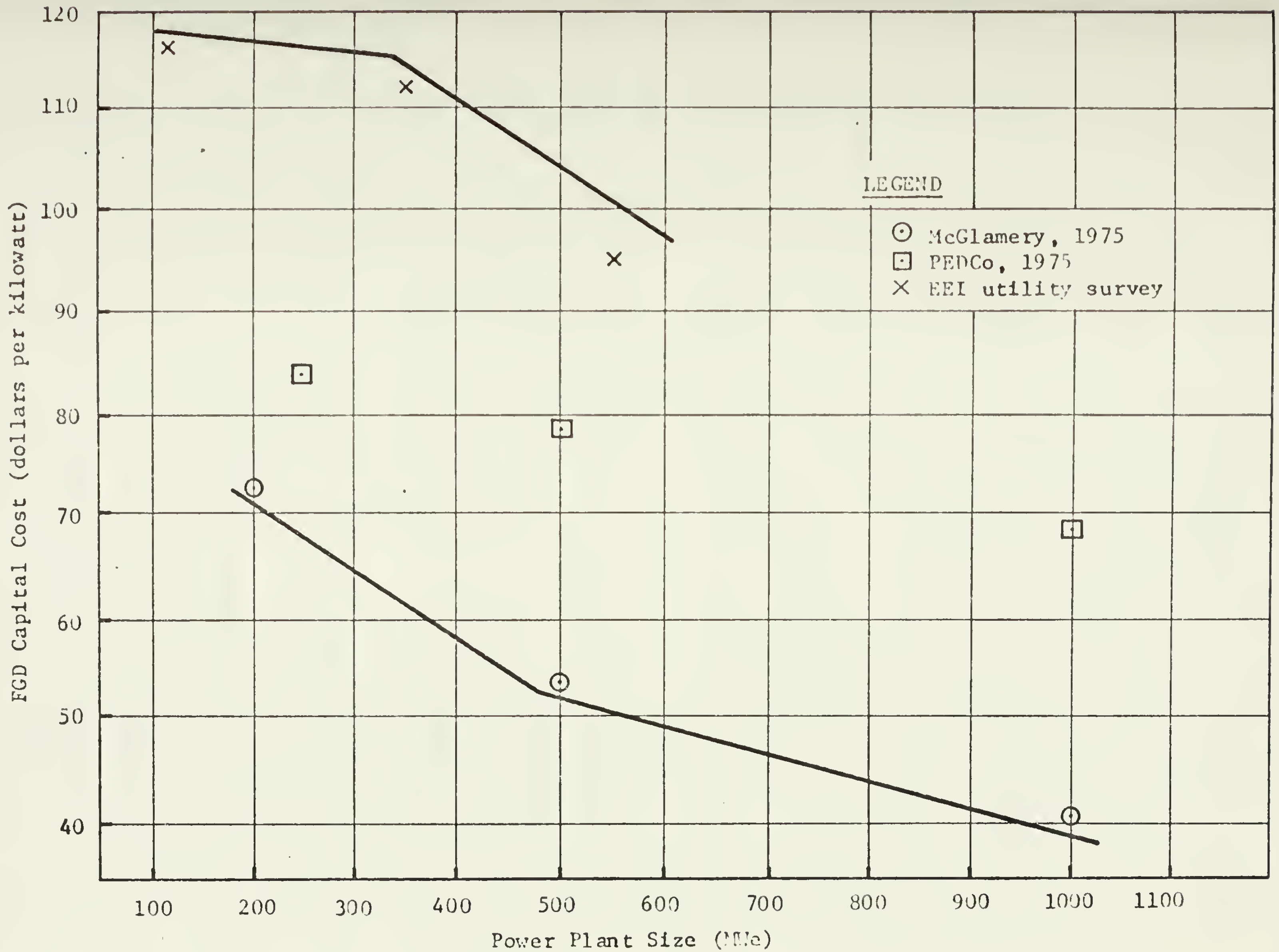


Figure 3.10. Adjusted Unit Capital Cost Estimates For Wellman-Lord Scrubbing System (1975 $)



than the estimates reported by the utilities.

On the other hand, the estimates by McGlamery, et al., appear to be unrealistically low. For instance, with respect to the limestone process, at 500 MWe their estimate is 8% lower and at 1000 MWe it is almost 23% lower than the lowest manufacturer's estimate. There is no reason to believe that actual capital costs will be less than the manufacturer's estimates.

The model plant estimates by PEDCo appear to be "best" estimates of capital costs for both processes. For the limestone system, PEDCo's estimates approximate the average costs estimated by the manufacturers, and for both types of systems PEDCo's estimates approximate the mean value for estimates from all sources. PEDCo's estimates, as modified and including replacement power costs, will be used in this analysis. The unit cost for the 250 MWe installation analyzed by PEDCo will be used as a proxy for the 200 MWe plant in this analysis.

Detailed cost breakdowns of the two processes are displayed in Tables 3.18 and 3.19. In order to reference FGD capital costs to the beginning of power plant construction in 1978, an inflation rate of 6% per year will be assumed from 1975 to 1978. A design basis description of these processes is included in Appendices D and E.

There is an uncertainty associated with any process cost estimate. To account for this, a range of estimates was made as specified in Table 3.20. The high variant case for both processes is the utility cost estimates. The low variant case for the limestone process is the lowest manufacturer's estimate as displayed in Figures 3.7 and 3.8. The low variant case for the Wellman-Lord process is the PEDCo estimate shown in Figures 3.9 and 3.10.

Flue gas desulfurization operating and maintenance costs are dependent upon the number of hours the system is operated per year, which is a function

TABLE 3.18

CAPITAL COST BEST ESTIMATES FOR LIMESTONE SLURRY SCRUBBING SYSTEM ON NEW COAL-FIRED PLANT (1975$)

COST COMPONENTS	1000 MWe	500 MWe	250 MWe
DIRECT COSTS			
A. Limestone preparation			
Conveyors	497,162	399,990	351,219
Storage silo	149,745	96,687	68,893
Ball mills	823,242	645,591	552,532
Pumps and motors	327,277	180,291	108,847
Storage tanks	467,242	190,896	92,088
B. Scrubbing			
Absorbers	13,605,211	7,030,881	3,595,366
Fans and motors	1,297,030	670,277	342,755
Pumps and motors	518,502	264,529	151,107
Tanks	819,668	419,172	233,586
Reheaters	2,954,254	1,526,695	780,696
Soot blowers	815,808	407,904	271,936
Ducting and valves	6,560,858	2,254,706	961,123
C. Sludge disposal			
Clarifiers	350,357	251,975	180,138
Vacuum filters	176,107	177,603	180,567
Tanks and mixers	11,690	6,745	6,575
Fixation chem. storage	49,865	32,196	22,941
Pumps and motors	117,090	67,587	41,668
Sludge pond	2,748,498	1,976,706	1,413,162
Mobile equipment	53,416	53,416	53,416
TOTAL DIRECT COSTS	32,343,031	16,653,847	9,408,596

Engineering costs	2,587,442	1,499,026	1,034,945
Const. field expenses	3,234,303	1,832,143	1,223,117
Contractor's fees	1,617,151	832,792	658,601
Contingency	2,910,872	1,665,585	1,034,945
Freight	323,430	166,558	94,085
Taxes	485,145	249,837	141,128
Spare parts	161,715	83,279	47,042
TOTAL INDIRECT COSTS	11,320,060	6,329,223	4,233,865
TOTAL DIRECT AND INDIRECT COSTS	43,663,091	22,983,070	13,642,461
START-UP AND MODIFICATION	3,493,047	1,838,645	1,091,396
INTEREST	3,493,047	1,838,645	1,091,396
TOTAL INSTALLED COST			
Dollars	50,649,186	26,660,360	15,825,255
$/KW	50.6	53.3	63.3
1978 INSTALLED COST*			
$/KW	60.3	63.5	75.4
1978 REPLACEMENT POWER COSTS*			
$/KW	11.5	13.8	18.6
1978 TOTAL CAPITAL COST*			
$/KW	71.8	77.3	94.0

* Assumes 6% annual inflation 1975 - 1978

TABLE 3.19

CAPITAL COST BEST ESTIMATE FOR WELLMAN-LORD SCRUBBING SYSTEM (1975$)

COST COMPONENTS	1000 MWe	500 MWe	250 MWe
DIRECT COSTS			
A. Na_2CO_3 preparation			
Storage silo	150,506	84,177	49,432
Vibrating feeder	4,557	4,555	4,553
Storage tank	81,307	62,063	47,531
Agitators	16,126	16,126	16,126
Pumps and motors	1,456	1,456	1,456
B. Scrubbing			
Absorbers	17,917,650	9,259,457	4,734,949
Fans and motors	165,133	170,675	174,554
Pumps and motors	524,419	271,008	138,583
Reheaters	3,131,510	1,618,297	827,538
Soot blowers	2,175,488	1,087,744	543,872
Ducting	2,099,911	1,006,379	449,787
Valves	2,321,956	999,947	511,336
C. Purge treatment	3,914,623	2,058,787	1,086,619
D. Regeneration			
Pumps and motors	716,100	419,132	256,634
Evaporators	10,838,867	5,632,131	2,895,317
Heat exchangers	1,430,590	739,960	378,188
Tanks	117,947	76,000	48,582
Stripper	200,011	145,040	104,901
Blower	465,436	240,743	123,042
TOTAL DIRECT COSTS	46,273,606	23,893,688	12,393,015

INDIRECT COSTS			
Engineering costs	4,627,360	2,628,305	1,611,091
Construction expenses	4,627,360	2,628,305	1,611,091
Contractor's fees	2,313,680	1,672,558	857,511
Contingency	4,164,624	2,389,368	1,363,231
Freight	462,736	238,936	123,930
Taxes	694,104	358,405	185,895
Spare parts	231,368	119,468	61,965
TOTAL INDIRECT COSTS	17,121,233	10,035,345	5,824,714
TOTAL DIRECT AND INDIRECT COSTS	63,394,839	33,929,033	18,217,729
START-UP	5,071,587	2,714,322	1,457,418
INTEREST	5,071,587	2,714,322	1,457,418
TOTAL INSTALLED COST			
Dollars	73,538,013	39,357,678	21,132,565
$/KW	73.5	78.7	84.5
1978 INSTALLED COST*			
$/KW	87.5	93.8	100.7
1978 REPLACEMENT POWER COSTS*			
$/KW	11.5	13.8	18.6
1978 TOTAL CAPITAL COST*	99.0	107.6	119.3

* Assumes 6% annual inflation 1975 - 1978

TABLE 3.20

ESTIMATED FLUE GAS DESULFURIZATION CAPITAL COSTS, INCLUDING REPLACEMENT POWER COSTS, FOR LIMESTONE AND WELLMAN-LORD SYSTEMS INSTALLED ON NEW COAL-FIRED POWER PLANT (1978 $)

PROCESS	LOW VARIANT ($/KW)	BEST ESTIMATE ($/KW)	HIGH VARIANT ($/KW)
Limestone Slurry			
200 MWe	85	94	115
500 MWe	72	77	100
1000 MWe	63	72	100
Wellman-Lord			
200 MWe	119	119	152
500 MWe	108	108	127
1000 MWe	99	99	127

Note: Assumes 90% SO_2 removal.

of the power plant availability. This raises the issue of FGD reliability and its effect on overall power plant availability. Data for limestone installations on coal-fired plants indicate availabilities as low as 40 per cent in some instances during 1974 [65]. These systems have encountered numerous chemical and mechanical problems including scaling, plugging, corrosion, and mechanical failures. However, the Environmental Protection Agency has reported to Congress that the "chemical problems have been largely solved by control of the process chemistry" and that new FGD units are expected to realize 95 to 99 per cent availability over long periods of time [66]. Though that assessment may be overly optimistic, the current analysis will also assume a high availability for both the limestone and Wellman-Lord processes. To wit, the availability of the base-load 1000 MWe plant will be reduced from 75 to 70 per cent with the FGD installation, whereas the availability of the intermediate and peak-load plants will remain unchanged at 50 and 20 per cent respectively. The effect of changing this assumption will be discussed presently.

Using the cost factors specified in Table 3.16 and the quantities of raw materials and utilities specified for the PEDCo model FGD systems, the operating and maintenance costs were calculated for both processes [Tables 3.21 and 3.22]. Then, in the same manner as before, the annualized costs of operating a limestone slurry and a Wellman-Lord process were calculated. These costs are presented in Table 3.23 and Figure 3.11. Finally, the range of annual FGD costs is presented in Table 3.24. The high and low variants are a function of changing FGD capital cost estimates; high and low estimates of operating and maintenance costs were not made.

Interestingly, in the base-load case assuming byproduct credit for the Wellman-Lord process, the two processes have annualized costs that are

TABLE 3.21

LIMESTONE SLURRY SCRUBBING, OPERATING AND MAINTENANCE COSTS (1975 $)
(90% SO_2 REMOVAL, NEW COAL-FIRED PLANT)

	1000 MWe	500 MWe	200 MWe
LOAD FACTOR (%)	70	50	20
ANNUAL ELECTRICAL GENERATION (KWh/yr)	6.13×10^9	2.19×10^9	3.5×10^8
COST COMPONENT			
RAW MATERIAL			
Limestone			
Quantity, ton/hr	40.4	20.9	8.4
Cost, $/yr	1,487,414	549,628	88,361
Fixation chemical			
Quantity, ton/hr	98.8	51.1	20.4
Cost, $/yr	1,212,513	447,942	71,530
UTILITIES			
Electricity			
Quantity, KW	11,084	5,826	2,330
Cost, $/yr	1,700,341	638,383	102,123
Process water			
Quantity, gal/min	302.6	156.3	62.5
Cost, $/yr	2,005	739	118
Reheat steam			
Quantity, MBtu	134.4	69.4	27.8
Cost, $/yr	626,776	231,179	37,041

OPERATING LABOR			
Direct labor			
Quantity, man/day	3	2	2
Cost, $/yr	210,384	140,256	140,256
Supervisory, $/yr	31,557	21,038	21,038
MAINTENANCE, $/yr	2,264,010	1,332,400	846,720
OVERHEAD			
Plant, $/yr	1,576,405	746,847	504,407
Payroll, $/yr	48,388	32,258	32,258
TOTAL O & M COSTS			
1975 $/yr	9,159,793	4,140,667	1,843,852
1975 mills/KWh	1.49	1.89	5.27
1978 $/yr*	10,909,460	4,931,600	2,196,057
1978 mills/KWh*	1.78	2.25	6.27

* Assumes 6% annual inflation 1975 - 1978

TABLE 3.22

WELLMAN-LORD REGENERABLE SCRUBBING PROCESS, OPERATING AND MAINTENANCE COSTS
(1975 \$, 90% SO_2 REMOVAL, NEW COAL-FIRED PLANT)

	1000 MWe	500 MWe	200 MWe
LOAD FACTOR, %	70	50	20
ANNUAL ELECTRICAL GENERATION (KWh/yr)	6.13×10^9	2.19×10^9	3.5×10^8
COST COMPONENT			
RAW MATERIAL			
Soda ash			
Quantity, ton/hr	2.09	1.08	0.43
Cost, \$/yr	705,356	260,350	41,656
UTILITIES			
Electricity			
Quantity, KW	9595	5495	2198
Cost, \$/yr	1,471,920	602,114	96,338
Reheat steam			
Quantity, MBtu/hr	142.5	73.6	29.5
Cost, \$/yr	664,550	245,167	39,226
Process steam			
Quantity, MBtu/hr	581.6	300.8	120.5
Cost, \$/yr	2,712,298	1,001,988	160,318
Process water			
Quantity, gal/min	9305.9	4813.0	1925.0
Cost, \$/yr	61,671	22,783	3,645

OPERATING LABOR			
Direct labor			
Quantity, men/day	4	2	2
Cost, $/yr	280,512	140,256	140,256
Supervisory, $/yr	42,076	21,038	21,038
MAINTENANCE, $/yr	2,313,650	1,433,580	867,510
OVERHEAD			
Plant, $/yr	1,318,119	797,437	514,402
Payroll, $/yr	64,517	32,258	32,258
TOTAL O & M COSTS			
1975 $/yr	9,634,669	4,556,971	1,916,647
1975 mills/KWh	1.57	2.08	5.48
BYPRODUCT CREDIT			
Sulfuric acid			
Quantity, ton/hr	28.9	15.0	6.0
Credit, $/yr	3,546,723	1,314,900	210,384
Salt cake			
Quantity, ton/hr	2.09	1.08	0.43
Credit, $/yr	512,986	189,345	30,295
Total credit	4,059,709	1,504,245	240,679
NET O & M COSTS			
1975 $/yr	5,574,960	3,052,725	1,675,968
1975 mills/KWh	0.91	1.39	4.79
1978 $/yr*	6,639,866	3,635,844	1,996,104
1978 mills/KWh*	1.08	1.66	5.70

* Assumes 6% annual inflation 1975 - 1978

TABLE 3.23

ANNUALIZED COSTS OF FLUE GAS DESULFURIZATION PROCESSES
(1978 $, 90% SO_2 REMOVAL, NEW COAL-FIRED PLANT)

	1000 MWe	500 MWe	200 MWe
LIMESTONE SLURRY			
O & M COSTS, $/yr	10,909,460	4,931,600	2,196,057
FIXED CHARGES, $/yr (@ 17.62% of capital invest.)	12,651,160	6,810,130	3,312,560
TOTAL ANNUAL COST (1978)			
$/yr	23,560,620	11,741,730	5,508,617
mills/KWh	3.84	5.36	15.7
¢/MBtu	43	58	164
$/ton of coal	10.75	14.50	41.10
WELLMAN-LORD			
NET O & M COSTS, $/yr	6,639,866	3,635,844	1,996,104
FIXED CHARGES, $/yr (@ 17.62% of capital invest.)	17,443,800	9,479,560	4,204,132
TOTAL ANNUAL COST (w/ byproduct credit)			
$/yr	24,083,666	13,115,404	6,200,236
mills/KWh	3.93	5.99	17.7
TOTAL ANNUAL COST (w/o byproduct credit)			
$/yr	28,918,844	14,906,985	6,486,889
mills/KWh	4.72	6.82	18.5
¢/MBtu	52.8	73.8	194
$/tons of coal	13.20	18.45	48.43

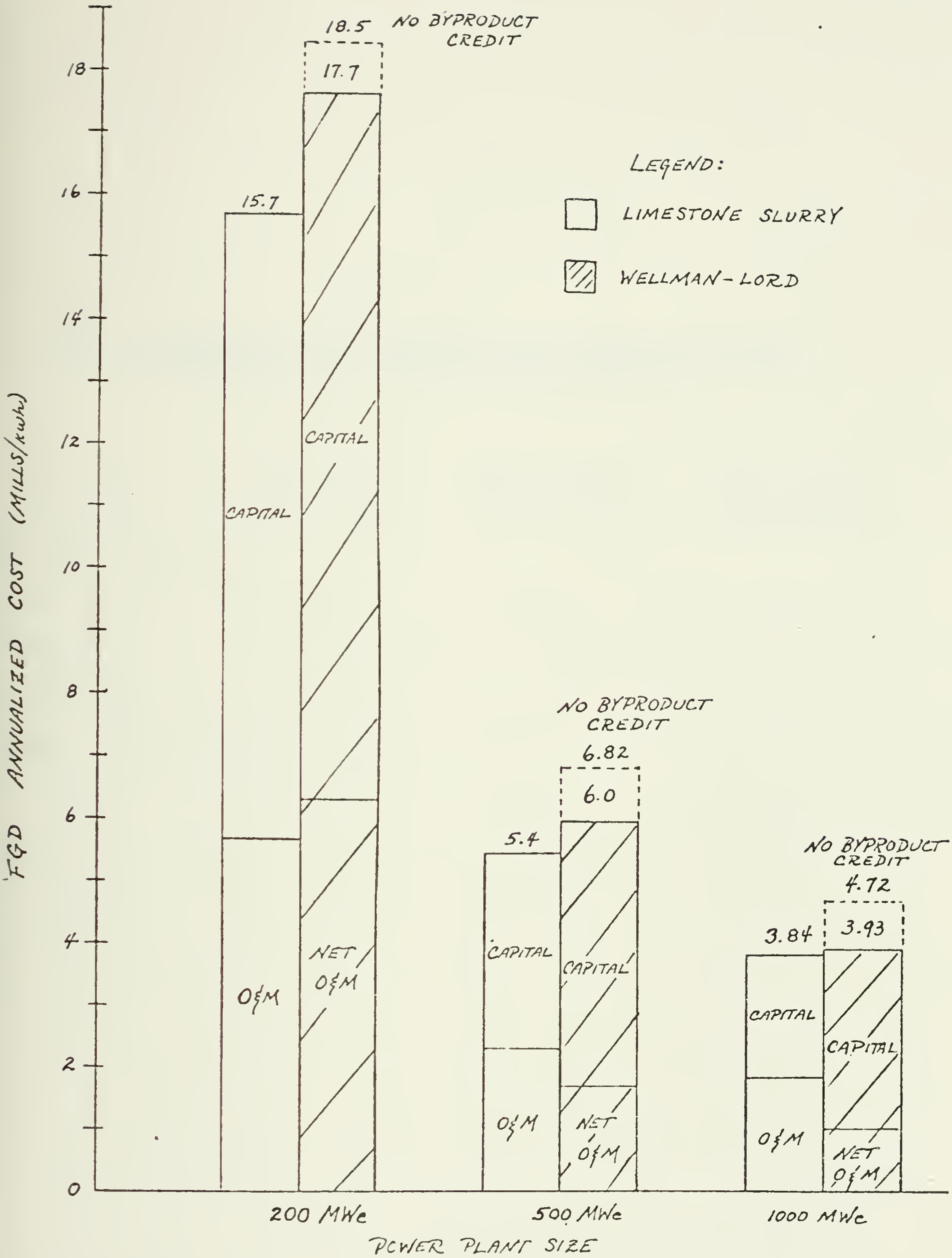


FIG. 3.11 BEST ESTIMATES of FGD ANNUALIZED COSTS (1978 $)
(90% SO_2 REMOVAL; NEW COAL-FIRED)

TABLE 3.24

RANGE OF ANNUAL COSTS OF FLUE GAS DESULFURIZATION PROCESSES INSTALLED ON NEW COAL-FIRED PLANT (1978 $)

PROCESS	LOW VARIANT (mills/KWh)	BEST ESTIMATE (mills/KWh)	HIGH VARIANT (mills/KWh)
Limestone Slurry			
200 MWe	14.5	15.7	18.0
500 MWe	5.0	5.4	6.4
1000 MWe	3.5	3.8	4.7
Wellman-Lord (w/ byproduct credit)			
200 MWe	17.7	17.7	21.0
500 MWe	6.0	6.0	7.0
1000 MWe	3.9	3.9	5.0

within 2% of each other. Without the byproduct credit, the Wellman-Lord process is approximately 23% more expensive to operate on an annual basis. In the intermediate and peak-load cases, the limestone process appears to be more advantageous, even with byproduct credit for the Wellman-Lord process, having an annualized cost approximately 12 per cent less than Wellman-Lord.

The annualized costs are highly dependent on the plant's load factor as Figure 3.12 indicates for the limestone slurry process. The high capital carrying charges associated with FGD systems would appear to make them economically unattractive for peak-load applications. In addition, the importance of high FGD reliability can be observed in the 1000 MWe case. A reduction in the plant load factor from 70 to 60% results in an approximate 13% increase in annualized costs for FGD operation.

There are other parameters, including flue gas flow rate, system redundancy, particulate control, sludge disposal options, site terrain, capacity factors, and escalation during construction which can affect the annual costs of operating an FGD system (see McGlamery, et al., and PEDCo). The present analysis will not attempt to examine these factors, though a base case has been established which would enable such an examination. However, one parameter which is of interest here is the SO_2 removal efficiency of the FGD system. All of the cost estimates thus far have assumed a 90% removal efficiency, but only an 80% removal efficiency is required to meet the New Source Performance Standards for SO_2. The potential savings of operating at a reduced removal efficiency are small, however. At the expense of doubling SO_2 emissions by weight to the atmosphere, capital investment savings of 3.6% and 4.5% are possible for the limestone and Wellman-Lord processes respectively [67]. Annualized costs would be reduced by

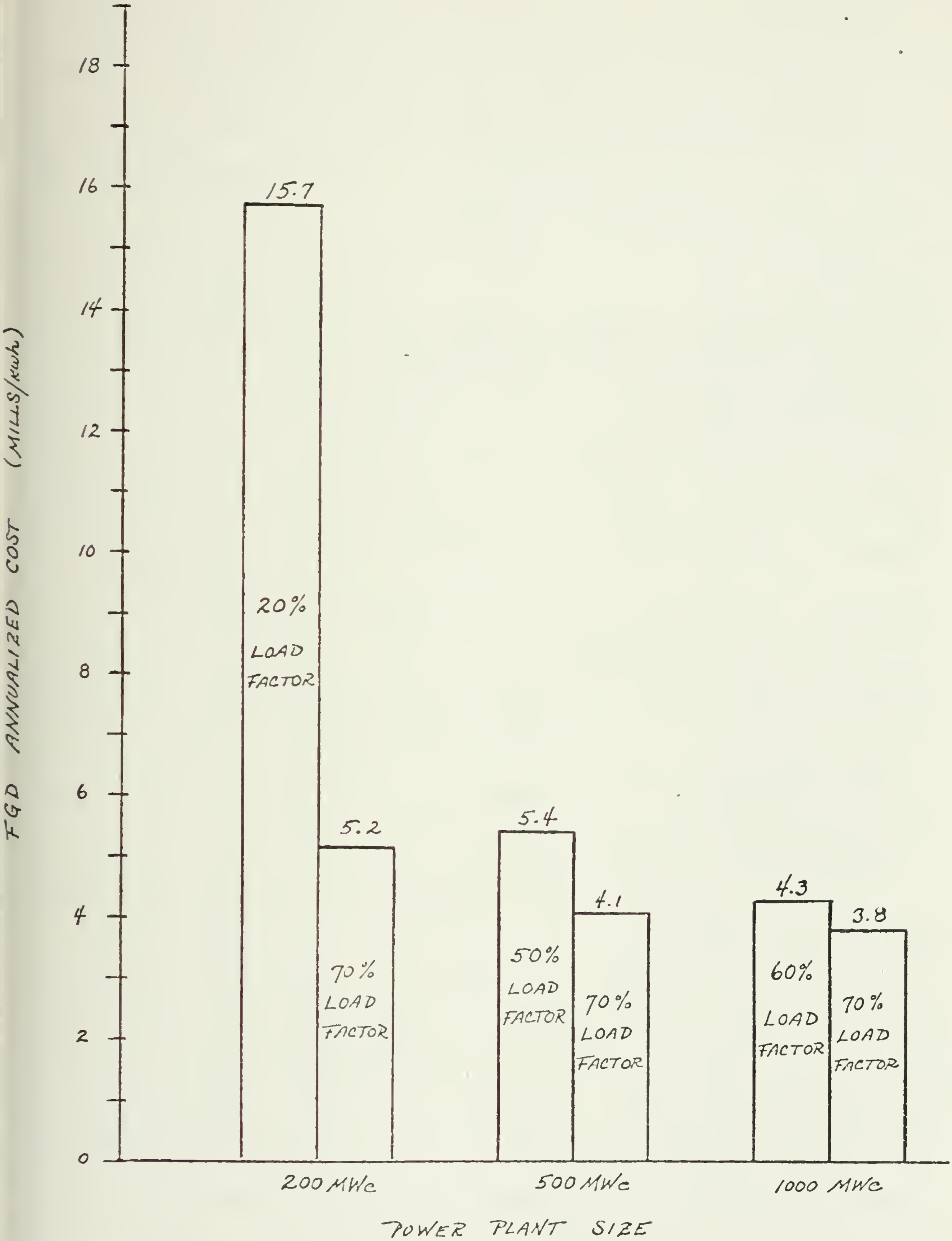


FIGURE 3.12 EFFECT of PLANT LOAD ON ANNUALIZED COSTS of LIMESTONE SCRUBBING (1978 $) ($90\%$ SO_2 REMOVAL ; NEW COAL-FIRED)

approximately 4.2 to 6.6 per cent respectively. From a policymaker's viewpoint, the potential savings do not appear to be large enough to justify considering other than a 90% SO_2 removal efficiency for flue gas desulfurization systems.

3.3.2.2 <u>Low Sulfur Coal</u>

A second alternative for meeting SO_2 emissions limitations is to burn coal which is sufficiently low in its natural sulfur content. To meet the New Source Performance Standards emission limitation of 1.2 pounds of SO_2 per MBtu heat input, a maximum sulfur content of 0.75% is permissible for coal with a heating value of 12,500 Btu/lb. In order to satisfy the Massachusetts fuel sulfur content regulations (currently in effect only until July, 1977) of 1.21 pounds of sulfur per MBtu, a maximum 1.5% sulfur coal with a heating value of 12,500 Btu/lb would be required. Though the uncontrolled combustion of the latter coal would not be permitted under current regulations since it would not satisfy the NSPS, it will be considered here to give an idea of the potential cost savings available from a change in the regulations.

For the purposes of examining the costs of controlling SO_2 emissions by burning low sulfur coal, it will be assumed that the only cost of control is the additional price paid for low sulfur coal compared to the price of 3.5% sulfur coal. It will be assumed that there are no additional costs associated with changes that may be necessary in boiler and electrostatic precipitator design as a result of burning low sulfur coal. Particulate collection efficiency will be assumed to remain the same as in the 3.5% sulfur coal case.

Coal prices are highly sensitive to the coal sulfur content as

exhibited in Figure 3.13. This phenomenon can be attributed to several factors. First, low sulfur coal is relatively scarce. Approximately 36 billion tons of coal with less than 0.7% sulfur exist in the Appalachian coal fields constituting only about 12 per cent of the region's coal reserves [68]. Most of this low sulfur coal is located in West Virginia and eastern Kentucky. Second, low sulfur coal production is frequently more expensive because the coal occurs in deep, fairly thin seams. And third, under tight market conditions an economic rent for low sulfur coal is potentially available to coal producers which is equivalent to the difference in cost of low sulfur coal and its alternatives (i.e., a rent may be available equal to the difference between delivered high sulfur coal plus FGD costs and delivered low sulfur coal costs).

An additional factor associated with low sulfur coal is its degree of availability to electric utilities. Gordon [69] indicates that utilities have not had widespread success in securing contracts for such coals, since the steel industry and foreign buyers have apparently contracted for the best reserves of low sulfur coal. Indeed, approximately 30 per cent of annual Appalachian coal production is committed to metallurgical use. A study conducted by MITRE Corporation [70] concludes that "very limited commercially available mineable reserves of low sulfur coal, particularly at the 0.6 and 0.8 pounds of sulfur per MBtu level, exist within the Appalachian and Interior coal regions to support the Eastern utility industry." However, according to Gordon, given sufficient demand the low sulfur coal could be bid away from the existing commitments, albeit at a very high price.

An excellent examination of present coal prices was recently conducted by the Center for Energy Policy (CEP) for the Federal Energy Administration [71]. Coal price estimates were established by investigating signed utility coal

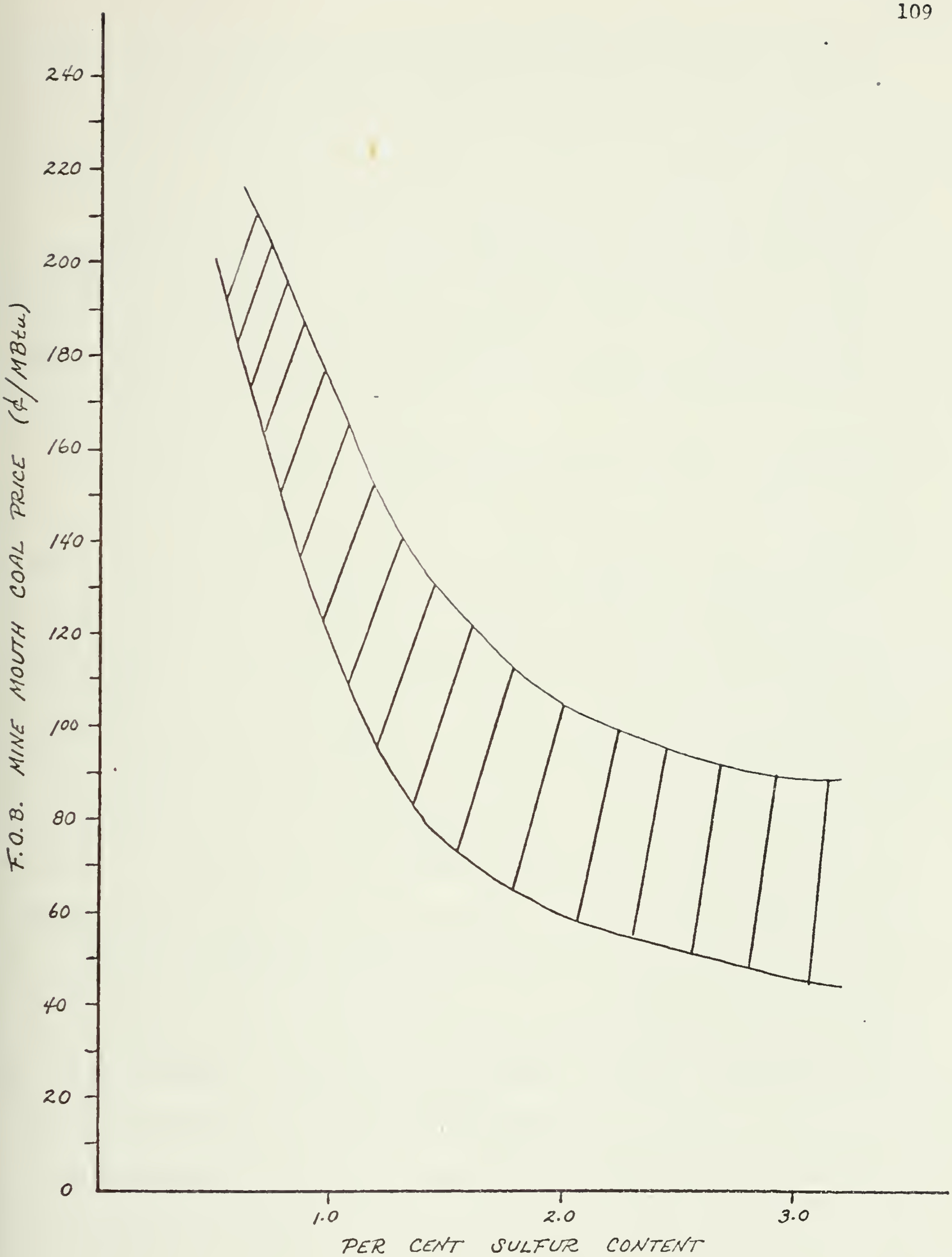


FIGURE 3.13 EASTERN U.S. COAL PRICE SENSITIVITY TO SULFUR CONTENT (1976 $)

contracts dating back to 1970, listings and analysis of the 1976 contracts and quotations, and other analytic reports [72]. The price estimates and the future state of the market were validated through a survey of utilities in the Eastern United States which were buying coal or obtaining coal bids in 1976, and through interviews with executive management of several coal producers. Thus, these estimates are quite representative of the price for coal under long-term contract to electric utilities as of early 1976.

Three types of coal were considered in the CEP study as listed in Table 3.25. These types approximate coal which meets the NSPS as burned, the coal which would meet state sulfur content regulations, and the coal which would be burned if a FGD system were installed on the proposed plant. They will be referred to as low sulfur, medium sulfur, and high sulfur coal, respectively. The high sulfur coal considered by CEP had a sulfur content of 2.5%, whereas the coal used in the proposed plant in conjunction with a FGD system would be 3.5% sulfur. However, as Figure 3.13 demonstrates, the price sensitivity to sulfur content decreases considerably beyond 2.5% sulfur. Though a 3.5% sulfur coal may actually be available at slightly lower price, this effect will be ignored. Also, in this analysis, the differences in heating value and ash content amongst the coals will be assumed to have a minimal effect on price in comparison with coal sulfur content.

The estimates of long-term contract prices for coal F.O.B. at the mine are, in 1975 dollars:

Low sulfur (0.7%): 173 ¢/MBtu
43.25 $/ton

TABLE 3.25

COAL TYPE SPECIFICATIONS

SPECIFICATIONS (as received)	LOW SULFUR	MEDIUM SULFUR	HIGH SULFUR
Heating value (Btu/lb max.)	13,000	12,500	12,000
Ash content (lb/MBtu max.)	6.4 (8%)	9.6 (12%)	11.2 (14%)
Sulfur content (lb/MBtu)	0.54 (.7%)	1.21 (1.4%)	2.0 (2.5%)

Source: Center for Energy Policy, Inc., The Impact of Coal Conversion on New England Energy Policy (Boston, Massachusetts: Center for Energy Policy, Inc., 1976).

Medium sulfur (1.4%): 100 ¢/MBtu
25.00 \$/ton

High sulfur (3.5%): 75 ¢/ton
18.75 \$/ton

Forecasting future coal prices is fraught with uncertainty. Though coal prices have recently followed the trend of world oil prices, there is some reason to believe that the upward pressure on coal prices may be eased somewhat in the next few years. The large increase in domestic coal prices in 1973 and 1974 was primarily due to a surge in demand coupled with the inability of the coal industry to expand production rapidly, and to increased production costs as a result of more stringent federal mine safety regulations [73]. Several sources have concluded that the coal market will soon stabilize and that coal prices will increase at approximately the general inflation rate, at least over the next decade [74]. Barring future oil embargoes or the dissolution of OPEC, this is probably a reasonable assumption to make in the initial analysis. Coal prices will be discussed in greater detail in Chapter 4. For the present, the price of all three types of coal will be assumed to remain constant in 1975 dollars. High and low variants of 1978 coal prices will be assumed to be 10 per cent of the CEP estimates to account for changes in production costs greater or less than the general inflation rate.

The marginal costs of controlling SO_2 emissions by burning low sulfur coal are shown in Table 3.26, expressed in 1978 dollars. Again, a 6% annual inflation rate was assumed from 1975 to 1978. If the estimated coal prices are representative of the current coal market, it would appear that coal producers are not collecting an economic rent on low sulfur (0.7%) coal. Since marginal low sulfur coal costs are substantially higher than the equivalent costs of FGD, for instance, other factors must be contributing

TABLE 3.26

ANNUALIZED COSTS OF SO_2 CONTROL THROUGH THE USE OF LOW SULFUR COAL

COAL COST ASSUMPTIONS	F.O.B. PRICE AT MINE ($/ton) 1975 $	1978 $	DIFFERENTIAL (1978 $)
Coal type			
Low sulfur (0.7%)	43.25	51.50	
			21.72
Medium sulfur (1.4%)	25.00	29.78	
			7.45
High sulfur (3.5%)	18.75	22.33	

DEGREE OF SO_2 CONTROL	COST OF COMPLIANCE COMPARED w/ 3.5% SULFUR (1978 $) 1000 MWe	500 MWe	200 MWe
New Source Standards (1.2 lb/MBtu)			
$/ton	29.17	29.17	29.17
¢/MBtu	117	117	117
mills/KWh	10.0	10.5	10.9
Range of cost, mills/KWh (± 10% of best estimate)	9.0 - 11.0	9.5 - 11.5	9.8 - 12.0
	*****		
State Sulfur Regulation (2.4 lb/MBtu)			
$/ton of coal	7.45	7.45	7.45
¢/MBtu	30	30	30
mills/KWh	2.6	2.7	2.8
Range of cost, mills/KWh (± 10% of best estimate)	2.3 - 2.9	2.4 - 3.0	2.5 - 3.1

to the high price. It has been suggested that one important factor is depletion of low sulfur deposits [75]. In economic terms, depletion is manifested in the mining of coal from increasingly costly seams. As a result, the cost of expanding production becomes greater and the cost of coal per ton at the mine is larger.

3.3.2.3 Coal Beneficiation

Sulfur occurs in coal in three principal forms: sulfate, organic, and pyritic. The amount of sulfate is almost always negligible, usually less than 0.05% of the total sulfur content. The organic sulfur fraction may be 20 to 60 per cent of the total sulfur content. Organic sulfur is chemically bonded to the carbon-hydrogen coal polymer and is distributed uniformly throughout the coal. It will withstand separation unless the coal is chemically altered as in the solvent refining process. Pyritic (FeS_2), or inorganic sulfur occurs as discrete particles in crystal form and constitutes 40 to 80 per cent of the total sulfur. Fine pyrite ($\sim 1\mu$ diameter) is difficult to remove using coal cleaning techniques. It is the coarse pyrite ($\sim 100\mu$ diameter) which can be separated from the coal using a beneficiation process.

Coal beneficiation is a well-established technology that has had wide industrial application. A typical beneficiation process is depicted schematically in Figure 3.14. The coal is initially crushed and screened and divided into two streams by floating it in a controlled specific gravity liquid. Particles with a high pyritic sulfur content sink and are rejected, whereas particles low in pyritic sulfur float. In a multi-stage process, the float coal from the initial wash would be washed again at a lower specific gravity. This float coal would be dried and sent to clean coal storage. The

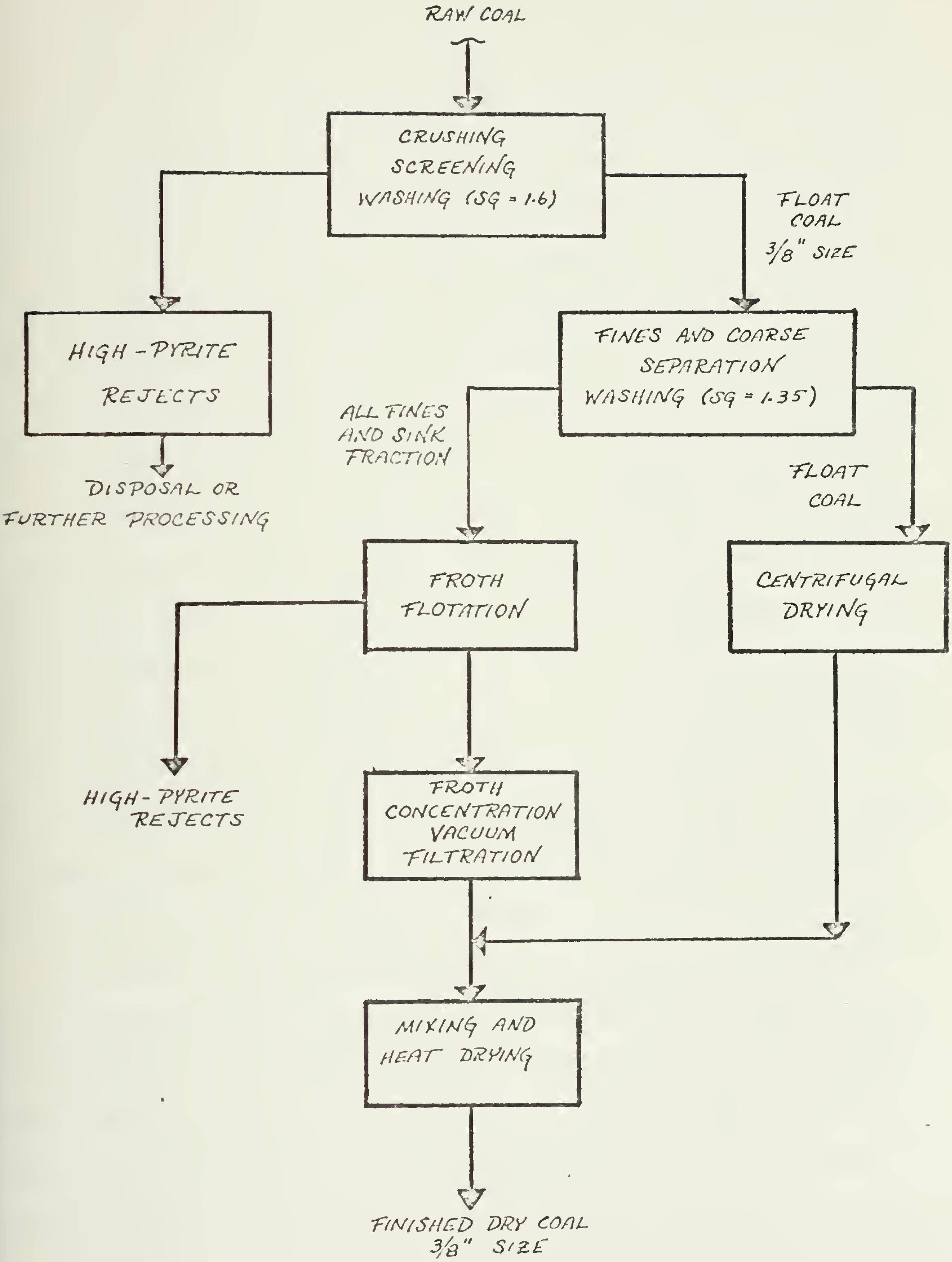


FIGURE 3.14 SCHEMATIC OF TYPICAL TWO-STAGE COAL BENEFICIATION PROCESS

sink coal from the second wash is sent to a system of froth flotation cells (froth of #2 fuel oil, methyl isobutyl carbinol and water) in which the separation is based on a difference in the surface tension properties of high and low pyrite particles. The froth is then sent to concentrating units and vacuum filtration while the sink fraction is rejected. After filtration, the clean coal stream is dried and sent to clean coal storage. The clean coal from this process typically retains 90 per cent of the original heating value and 70 to 75 per cent of the material by weight.

There is a large variation amongst coals as to the potential reduction in sulfur content through beneficiation. The achievable sulfur content is a function of total sulfur content, the fraction of sulfur that is pyritic, and the fraction of the pyritic sulfur that occurs as coarse crystals. In order to determine whether a coal can be beneficiated to an extent sufficient to conform to the New Source Performance Standards, a more specific seam analysis must be available than is considered here. However, the Environmental Protection Agency has estimated that 20 per cent of Northern Appalachian coal can be beneficiated to such a degree [76]. Of course, a larger fraction of the coal could be beneficiated to meet Massachusetts fuel sulfur content regulations.

Preliminary detailed cost analysis of a model coal beneficiation plant has been performed by Breuer [77]. The model plant evaluated was assumed to be in Pennsylvania. Its design basis was 7,000 ton per day of product output operating 6,132 hours per year at full capacity (70% load factor) which is sufficient to supply an 800 MWe coal-fired power plant. The beneficiated coal is assumed to have a heating value of 14,000 Btu/lb. The capital cost of such a plant was estimated to be 25.9 million dollars in 1976. Total annualized costs of plant operation include operation and

maintenance costs, fixed capital charges, and the cost of the coal which is rejected from the process. These are summarized in Table 3.27.

The costs of beneficiation appear to be approximately equal to the incremental costs of buying the medium sulfur coal discussed in the previous section. If it were feasible to operate this plant such that a high sulfur coal could be beneficiated to a level that would satisfy the NSPS, the annualized costs would be less than either buying natural low sulfur coal or operating an FGD system. However, it is not likely that a 3.5 per cent sulfur coal could be beneficiated to a 0.7 per cent sulfur [78]. Thus, to obtain a beneficiated product of 0.7 per cent, a lower sulfur coal input would probably be needed resulting in a higher incremental cost of SO_2 control. This cost will not be estimated here because of insufficient information concerning the degree to which the Upper Freeport coal can be beneficiated.

Regardless of the exact cost of beneficiation, it is unlikely that the price of beneficiated coal offers a substantial economic advantage over the natural low sulfur and FGD options. First, if it did offer a substantial advantage, utilities would be buying beneficiated low sulfur coal and not natural low sulfur coal. This is not the case at present. Second, if the cost of producing an acceptable beneficiated coal is less than the cost of installing and operating an FGD system, for example, an economic rent would potentially be available to the beneficiated coal producer and would be approximately equal to the difference in the two costs of control. To wit, the price of beneficiated coal and its lowest alternative are likely to be comparable. Such an assupmtion will be made in this analysis.

ANNUALIZED COSTS OF COAL BENEFICIATION (7,000 TONS PER DAY OF PRODUCT; 70% LOAD FACTOR, 1976 $)

COST COMPONENT	ANNUAL QUANTITY	UNIT COST	ANNUAL COST ($)
Raw Material			
Coal rejected	4.82×10^{12} MBtu	$1.00/MBtu	4,820,000
#2 Fuel oil	2.33×10^{6} lb	$0.042/lb	97,860
Methyl isobutyl carbinol	5.27×10^{5} lb	$0.22/lb	115,940
Magnetite	2.25×10^{6}	$0.036/lb	81,000
Electricity	3.02×10^{7} KWh	$0.02/KWh	604,000
Operating Labor & Supervision	78,840 man-hrs	$8.00/hr	630,720
Maintenance	-----	-----	1,278,000
Plant Overhead	50% of operating labor + maintenance		954,360
Fixed Charges	17.62% of capital investment		4,563,600
TOTAL ANNUAL COST (1976)			13,145,000
TOTAL ANNUAL COST (1978)*			
1978 $			14,770,000
$/ton of product			8.26
¢/MBtu			29.5
mills/KWh (9200 Btu/KWh)			2.7

*Assumes a 6% inflation rate 1976 - 1978

Source: C.Thomas Breuer, A Comparative Assessment of Coal Combustion Technology Options Available to Electric Utilities During or Before 1990, Preliminary thesis draft, MIT, January, 1977.

3.3.3 Nitrogen Oxide Control

Nitrogen oxides are formed in the boiler during combustion in two ways: (1) molecular nitrogen in the combustion air is oxidized to NO at flame conditions; and (2) chemically combined nitrogen in the coal is converted to NO during combustion. A small amount of NO is further oxidized to NO_2 as the combustion gases cool, but most of the oxidation (usually less than 10 per cent) occurs after emission to the atmosphere under the influence of solar radiation. The combined emissions of NO and NO_2 are referred to as NO_x emissions.

From the data presently available, the complex relationships existing among the operating variables in coal-fired furnaces preclude establishing a relationship between NO_x emissions and increasing fuel nitrogen. But, it is known that the formation of NO_x is proportional to excess combustion air above stoichiometric air, flame temperature, and the residence time of combustion gases in the furnace. Current nitrogen oxide control methods are directed at controlling these boiler parameters. No economically feasible method has been found, at present, to remove NO_x from stack gases after it is formed.

Based on the NO_x emission factor discussed previously, the NO_x emissions from the proposed tangentially-fired boiler would just conform to the New Source Performance Standards. There are at least two effective techniques available for further reducing NO_x emissions. One technique is to operate the boiler with minimum excess air. The practical lower limit in coal combustion is determined by the level where excessive furnace slagging or unburned combustible emissions occur, and is approximately 18 to 25 per cent excess air. A second technique is off-stoichiometric, or staged combustion. The first stage employs a fuel-rich (less than stoichiometric air) burner flame

to create a "volatilization" zone in which the volatiles in the coal are distilled off. After significant heat removal in the first stage, the second stage consists of an air-rich flame zone in which the remainder of the excess air requirement is satisfied and the combustion is completed on the carbon particles. Figure 3.15 presents a schematic view of staged combustion. The excess air added in the second stage is admitted to the furnace through over-fire ports located at the top of the furnace. Staged combustion firing requires no additional power to operate. Field tests have demonstrated that by lowering the level of excess air, in addition to using staged combustion, 40 to 50 per cent reductions in NO_x emissions are possible without undesirable side effects [79].

Thus, it will be assumed that it is possible to achieve the applicable NO_x emission limitations for the proposed plant without incurring significant additional capital investment or operating costs.

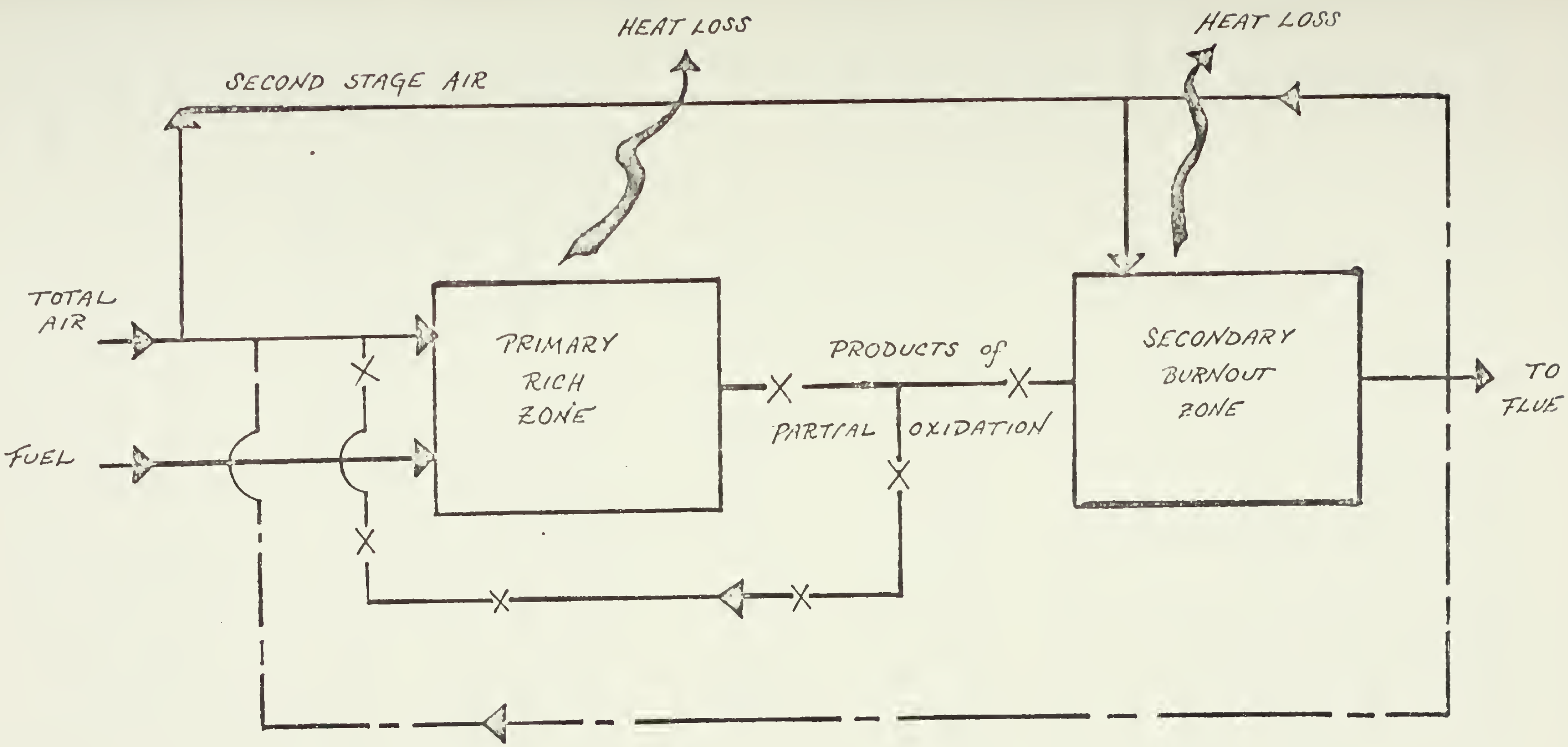


FIGURE 3.15 SCHEMATIC of STAGED COMBUSTION FOR NO_x CONTROL

3.4 Ambient Air Quality Analysis

Having identified the most significant pollutants resulting from coal combustion, and having discussed their control, it is necessary to estimate the effect of these pollutants on the ambient air quality in the vicinity of the power plant. The standard method of measuring this effect is a mathematical model which describes the dispersion of the pollutants in the atmosphere after their emission from the stack. The dispersion model suggested by Pasquill [80] and outlined by Turner [81] is used frequently as it will be in this analysis. The basic model is described in Appendix F.

By assuming that the ambient pollutant concentrations are calculated at ground level (z = 0) and at the centerline of the plume (y = 0) the Gaussian distribution simplifies to:

$$\chi\ (x,0,0;\ H) = \frac{Q}{\pi \sigma_y \sigma_z u} \exp \left[-1/2 \left(\frac{H}{\sigma_z} \right)^2 \right] \qquad [3.1]$$

where

χ = pollutant concentration in grams per cubic meter;

Q = uniform pollutant emission rate in grams per second;

u = mean wind speed affecting the plume in meters per second;

H = effective stack height in meters;

σ_y, σ_z = standard deviations of plume concentration distribution, in meters.

The effective stack height, H, is the height of the plume centerline at the point at which its direction of travel becomes essentially horizontal. It is equal to the sum of physical stack height, h, and the plume rise above the stack height, ΔH. The initial plume rise is due primarily to the

momentum and buoyancy of the gaseous emissions of the power plant. The ambient air mixes into the plume causing it to move horizontally at approximately the speed of the wind. As the plume bends over, it rises with a diminishing angle of inclination. An empirical expression proposed by Briggs [82] which is valid for fossil-fuel plants with heat emissions of 20 MW or greater will be used to calculate plume rise:

$$\Delta h = 1.6 \frac{F^{1/3}}{u} (x)^{2/3} \text{ meters} \tag{3.2}$$

The maximum plume rise is assumed to occur at a distance equivalent to ten stack heights (10h). The factor F is the flux of buoyant force carried by the stack gases, divided by π and the mean atmospheric density. In terms of the heat emission up the stack, Q_H in cal/sec:

$$F = 3.8 \times 10^{-5} Q_H \quad \frac{\text{meters}^4}{\text{seconds}^3} \tag{3.3}$$

The magnitude of the dispersion coefficient σ_z is a function of the turbulent structure of the atmosphere, surface roughness, sampling time over which the concentration is to be estimated, wind speed, and distance from the source. Turner's calculations assume the surface to be relatively open country. The sampling time is 10 minutes. The effects of the turbulent structure of the atmosphere and the wind speed are incorporated in the atmosphere stability classes shown in Table 3.28. Class A is the most unstable, class F the most stable atmospheric condition. The atmosphere is unstable when the temperature decreases with height above ground level at a rate greater than 5.4°F per 1000 feet. During this condition, vertical motions of pollutants are enhanced. When the temperature decreases at a lower rate or increases with height (inversion), the atmosphere is stable

TABLE 3.28

ATMOSPHERE STABILITY CLASSES

SURFACE WIND SPEED (m/sec)	DAY INCOMING SOLAR RADIATION STRONG	MODERATE	SLIGHT	NIGHT THIN OVERCAST (≥4/8 CLOUDS)	≤3/8 CLOUDS
<2	A	A-B	B		
2-3	A-B	B	C	E	F
3-5	B	B-C	C	D	E
5-6	C	C-D	D	D	D
>6	C	D	D	D	D

Source: D. Bruce Turner, Workbook of Atmospheric Dispersion Estimates, (Research Triangle Park, N.C.: U.S. Environmental Protection Agency, 1970).

and vertical motions are reduced. Stability class B is the maximum atmospheric instability applicable to a tall stack in the Boston vicinity. Values for σ_z as a function of stability class and downwind distance from the emission source can be found in Figure 3.3 in Turner.

Using this dispersion model it is possible to estimate the average annual pollutant concentrations resulting from the power plant emissions. The procedure would use historical wind rose data (a probability distribution of wind directions divided in 16 sectors of 22.5° each) for the plant site to apportion the plant's annual emissions to each wind sector. Then, historical atmospheric stability data would be used to calculate an average pollutant concentration as a function of downwind distance from the plant. The final product is an annual average pollutant concentration as a function of wind sector and distance. This method is used in many analyses. Due to time and resource constraints, annual average pollutant concentrations will not be estimated here. Rather, 24-hour pollutant concentrations will be estimated. This can be accomplished by defining the atmospheric condition which would result in the highest ground level concentrations and estimating the ambient concentrations which would occur during this condition only.

For an elevated source such as the power plant stack, the high ground level concentrations occur during unstable atmospheric conditions because of the more rapid downward dispersion of pollutants several hundred meters above ground level than under stable atmospheric conditions. Maximum pollutant concentrations would occur in unstable conditions when the plume becomes trapped between the ground surface and a stable layer, or inversion, aloft [Figure 3.16]. The dispersion calculations can be modified in this instance by considering the height of the inversion layer, L, (also referred to as the mixing height). In a Gaussian plume distribution, at a height of 2.15 σ_z

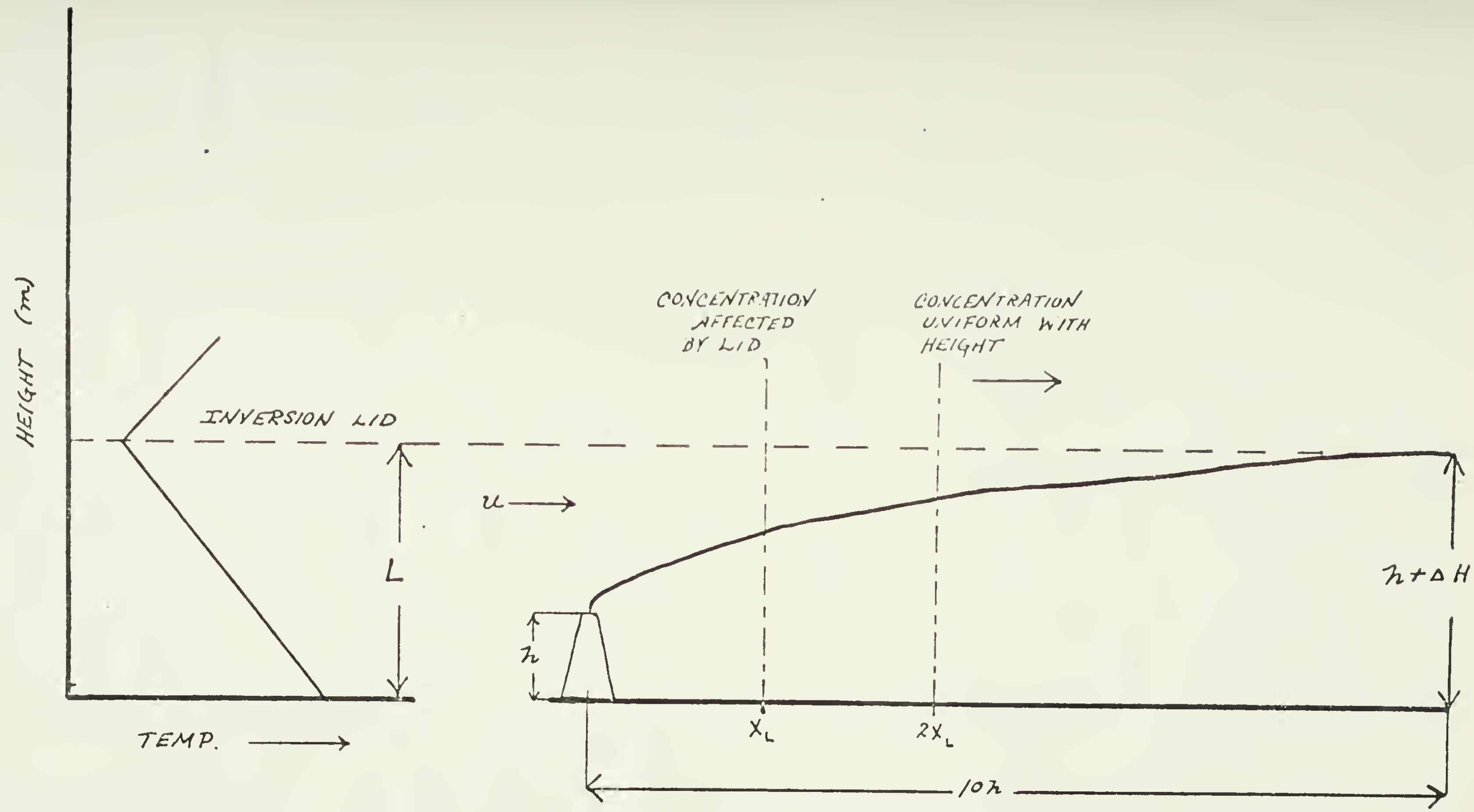


FIGURE 3.16 INVERSION CONDITION RESULTING IN MAXIMUM GROUND LEVEL POLLUTANT CONCENTRATIONS.

above the plume centerline the pollutant concentration is 10 per cent of the centerline concentration at the same distance. When one-tenth of the plume centerline concentration extends to the inversion layer, at height L, the inversion "lid" just begins to affect the pollutant concentration distribution. The horizontal distance from the source where $\sigma_z = L/2.15$ is defined as X_L. At this distance the plume is assumed to still have a Gaussian distribution. But at twice this distance, $2X_L$, the concentration is assumed to be uniformly distributed between the ground and the lid at height L. For distances greater than $2X_L$ the pollutant concentrations can be calculated from:

$$\chi\ (x,0,0;\ H) = \frac{Q}{\sqrt{2\pi}\ \sigma_y L u} \qquad [3.4]$$

Furthermore, the inversion that will result in the maximum concentration is one where the inversion height is equal to the effective plume rise (L = H). If the inversion height was greater than H, the pollutant concentration would obviously be smaller than if it were at H because of the greater volume available for dispersion. On the other hand, if the inversion occurred at a height less than H, the plume is likely to have sufficient buoyancy to penetrate the inversion. In this instance, the inversion would act as the barrier preventing the diffusion of the pollutants below the inversion and to the ground [33]. A relatively low ground level concentration would be the result.. The assumed mean wind speed will be that which results in the lowest plume rise (thus the lowest inversion height if L = H) during unstable atmospheric conditions. For the B stability class, this is a wind speed of 5 meters per second.

The dispersion equations discussed thus far estimate pollutant concentrations for an averaging time of approximately 10 minutes. Over a longer

period of time, the average concentration would be less because of changes in the mean wind direction and the resultant scattering of the plume from its initial downwind direction. To convert the 10 minute average concentrations to a longer averaging time period, the following relationships will be used:

$$\chi_{1\text{-hour}} = \left(\frac{10 \text{ min}}{60 \text{ min}}\right)^{1/5} \chi_{10\text{-min}} = 0.7\chi_{10\text{-min}}$$

$$\chi_{24\text{-hour}} = 1/4 \cdot \chi_{1\text{-hour}} \qquad \text{[Eq. 3.5]}$$

The maximum ambient 24-hour concentrations that would occur under inversion conditions will then be estimated for each pollutant.

Particulates

Assuming a particulate collection efficiency of 99.5 per cent, total annual particulate emissions from the 1000 MWe plant, without SO_2 control and with a load factor of 75 per cent, would be about 875 tons. In terms of the metropolitan Boston particulate emissions listed in Table 3.3, this power plant would increase annual particulate emissions approximately 1 per cent. Given this perspective, it might tentatively be concluded that the particulate emissions from the proposed power plants would have only a small impact on the area's ambient air quality.

In order to calculate the medium 24-hour concentrations of particulates, the parameters in Table 3.29 are needed. The stack heat emission rates are a function of the scrubber installation because of a 125°F difference in the stack gas exit temperature with and without a scrubber. The stack gas exit temperature from a plant with a scrubber is assumed to be 175°F, without a

TABLE 3.29

STACK HEAT EMISSION RATES AND INVERSION LID HEIGHTS

	1000 MWe	500 MWe	200 MWe
STACK HEAT EMISSION RATE, Q_H (cal/sec)			
w/o FGD system	4.5×10^7	2.3×10^7	9.6×10^6
w/ FGD system	2.7×10^7	1.4×10^7	5.8×10^6
INVERSION LID HEIGHT, L (meters)			
w/o FGD system	937	798	535
w/ FGD system	828	713	472

scrubber it is assumed to be 300°F. The inversion height was set equal to the effective stack height calculated from equations 3.2 and 3.3. Inversion heights on the order of those listed in Table 3.29 can be expected in Boston where the mean annual morning mixing height is 600 meters and the mean annual afternoon height is 1,025 meters [84].

Particulate emission rates are larger from a plant with a scrubber installation since the power plant thermal efficiency is less and the coal input is greater than in a plant without a scrubber. The particulate emission rates are, assuming a 99.5 per cent collection efficiency:

EMISSION RATES (g/sec)

	1000 MWe	500 MWe	200 MWe
w/o FGD	33.6	17.4	7.2
w/ FGD	34.5	17.8	7.4

The maximum 24-hour particulate concentrations as a function of downwind distance are listed in Table 3.30 and displayed in Figure 3.17. Strictly in terms of meeting ambient air quality standards, particulate emissions from any of the proposed power plants would not appear to be a problem. The maximum 24-hour concentration would occur at about 1 kilometer downwind of the plant and would have an approximate value of 3.7 $\mu g/m^3$. This is a small increment compared to the primary 24-hour standard of 260 $\mu g/m^3$, the secondary standard of 150 $\mu g/m^3$ and the allowable deterioration increment of 50 $\mu g/m^3$ for a 24-hour concentration. In addition, the maximum 24-hour particulate concentration at Salem would be increased by about 2 per cent, from 159 $\mu g/m^3$ [see Table 3.4] to 162.7 $\mu g/m^3$. If the plume extended 22 kilometers to Kenmore Square, where the highest particulate levels in Metropolitan Boston are recorded (see Appendix G), the maximum

TABLE 3.30

MAXIMUM 24-HOUR CONCENTRATION OF PARTICULATES FROM COAL-FIRED POWER PLANTS

DISTANCE DOWNWIND (km)	24-HOUR PARTICULATE CONCENTRATION ($\mu g/m^3$) 1000 MWe w/o FGD	w/ FGD	500 MWe w/o FGD	w/ FGD	200 MWe w/o FGD	w/ FGD
1.0	3.1	3.7	2.0	2.3	1.2	1.4
3.0	1.2	1.3	0.7	0.8	0.44	0.50
5.0	0.8	0.9	0.47	0.53	0.30	0.34
7.0	0.56	0.66	0.34	0.37	0.21	0.24
10.0	0.41	0.50	0.25	0.28	0.16	0.18
30.0	0.16	0.19	0.10	0.12	0.06	0.07
50.0	0.11	0.13	0.07	0.08	0.04	0.05
70.0	0.08	0.10	0.05	0.06	0.03	0.04
MAXIMUM 24-HOUR ($\mu g/m^3$)	3.1	3.7	2.0	2.3	1.2	1.4

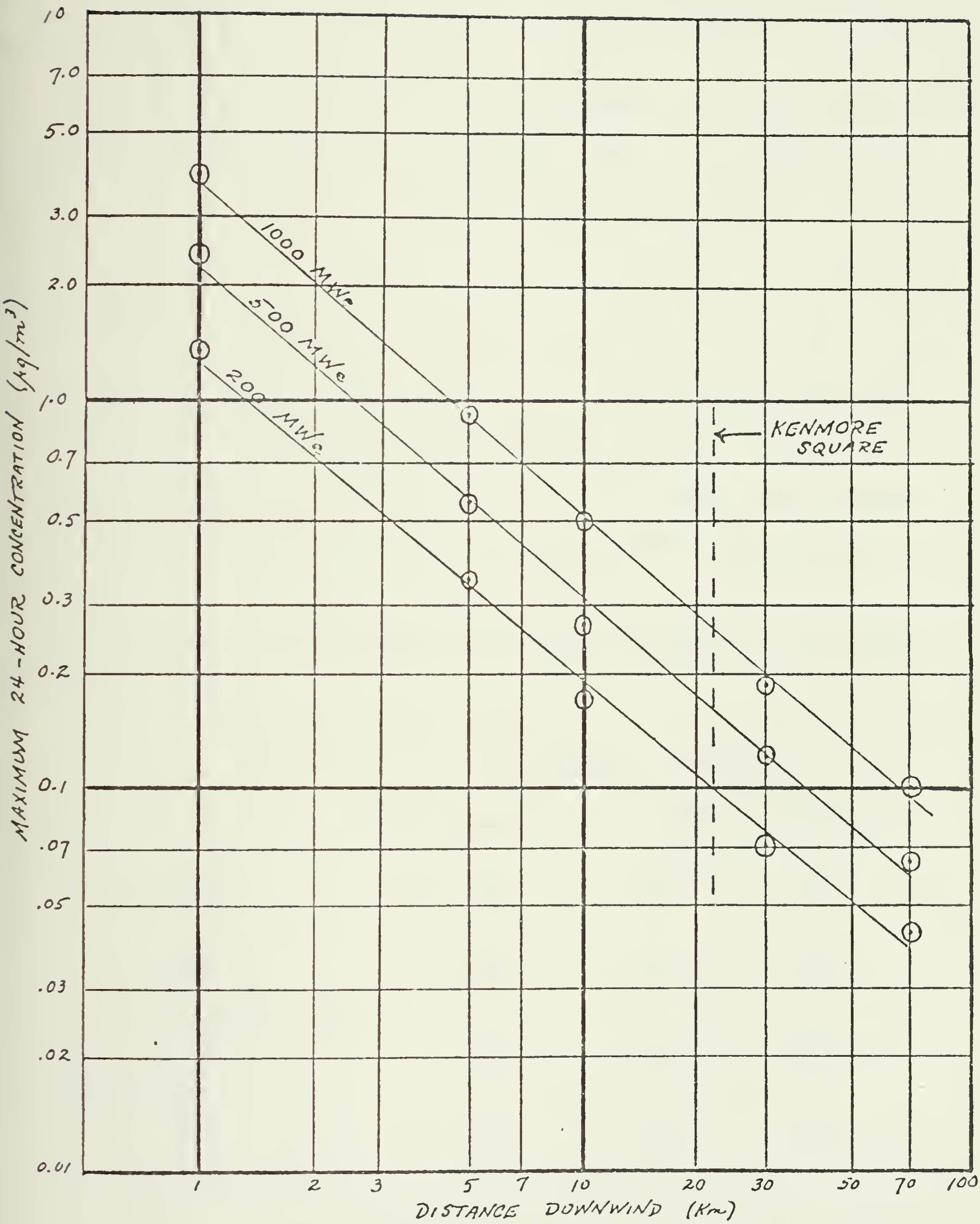


FIGURE 3.17 MAXIMUM 24-HOUR CONCENTRATIONS AS A FUNCTION of DOWNWIND DISTANCE

contribution of the 1000 MWe plant emissions to the 24-hour particulate concentration would be approximately 0.25 μg/m^3, compared with a maximum measured concentration of 269 μg/m^3.

Thus, at a cost of 0.57 to 2.0 mills per kilowatt-hour [see Table 3.10] particulate emissions from the proposed power plants can be reduced to an extent where their impact on ambient air quality is very small.

Sulfur Oxides

Even with 90 per cent removal of SO_2 from the flue gas, the 1000 MWe power plant would increase baseline SO_2 emissions in metropolitan Boston [Table 3.3] by more than 3 per cent. On this basis, sulfur oxide emissions are likely to cause a more significant impact on ambient air quality than particulates.

The maximum 24-hour SO_2 concentration will be estimated for the four cases listed below:

	SO_2 EMISSION RATES (g/sec)		
	1000 MWe	500 MWe	200 MWe
HS COAL (5.32 lb s/MBtu)	5830	3020	1250
MS COAL (2.24 lb s/MBtu)	2460	1270	525
LS COAL and FGD w/ 80% REMOVAL (1.12 lb s/MBtu)	1230	635	262
FGD w/ 90% REMOVAL (0.53 lb s/MBtu)	599	310	128

The assumption of an inversion at the effective stack height causes the SO_2 distribution to become uniform in the vertical direction within 1 kilometer of the plant. Since the only plume dispersion downwind is in

the horizontal direction, the ambient SO_2 concentrations decrease linearly as the plume travels downwind from about 1 kilometer. The maximum 24-hour concentrations as a function of downwind distance are listed in Table 3.31 and displayed in Figure 3.18 through 3.20.

The burning of a high or medium sulfur coal at any size plant would violate either the primary and secondary ambient 24-hour standard or the allowable increment for SO_2 emission increases under the significant deterioration regulations. The use of low sulfur coal or FGD with 80 per cent SO_2 removal at the 1000 MWe plant would violate the significant deterioration increment. Only the use of FGD with 90 per cent SO_2 removal would satisfy all of the current regulations for the 1000 MWe plant. Either low sulfur coal or FGD with 80 or 90 per cent would be satisfactory for the 500 MWe and 200 MWe plants.

Given the most stringent SO_2 emission control, FGD with 90 per cent SO_2 removal, the 24-hour maximum concentration would be increased approximately as indicated in Table 3.32. The increase in 24-hour concentrations would be significant in the vicinity of the plant, but at no time would the primary, secondary, or significant deterioration standards be closely approached. At Kenmore Square where the highest SO_2 concentrations in the Boston area are recorded, the increase in the maximum 24-hour SO_2 concentration would be quite small.

The marginal cost of SO_2 control as a function of emissions and ambient air quality are exhibited in Figures 3.21 through 3.26 for the three plant sizes. The minimum costs of SO_2 control for each plant size sufficient to satisfy all applicable standards are listed in Table 3.33. Flue gas desulfurization appears to be the least cost alternative for the base (1000 MWe) and intermediate (500 MWe) load plants. The use of low sulfur coal would

TABLE 3.31

MAXIMUM 24-HOUR SO_2 CONCENTRATIONS FROM COAL-FIRED POWER PLANTS WITH DIFFERENT SO_2 EMISSION RATES ($\mu g/m^3$)

DISTANCE DOWNWIND (km)	HIGH SULFUR (5.32 lb/MBtu)	MEDIUM SULFUR (2.24 lb/MBtu)	LOW SULFUR (1.12 lb/MBtu)	FGD (0.53 lb/MBtu)
1000 MWe				
1.0	560	237	118	65
5.0	134	56	28	16
10.0	72	31	16	8
30.0	29	12	6	3
70.0	14	6	3	1.7
500 MWe				
1.0	341	143	72	39
5.0	81	34	17	9
10.0	44	19	10	5
30.0	18	7	4	2
70.0	9	4	2	1
200 MWe				
1.0	210	88	44	24
5.0	50	21	11	6
10.0	27	11	6	3
30.0	11	5	3	1.3
70.0	5	2	1	0.6

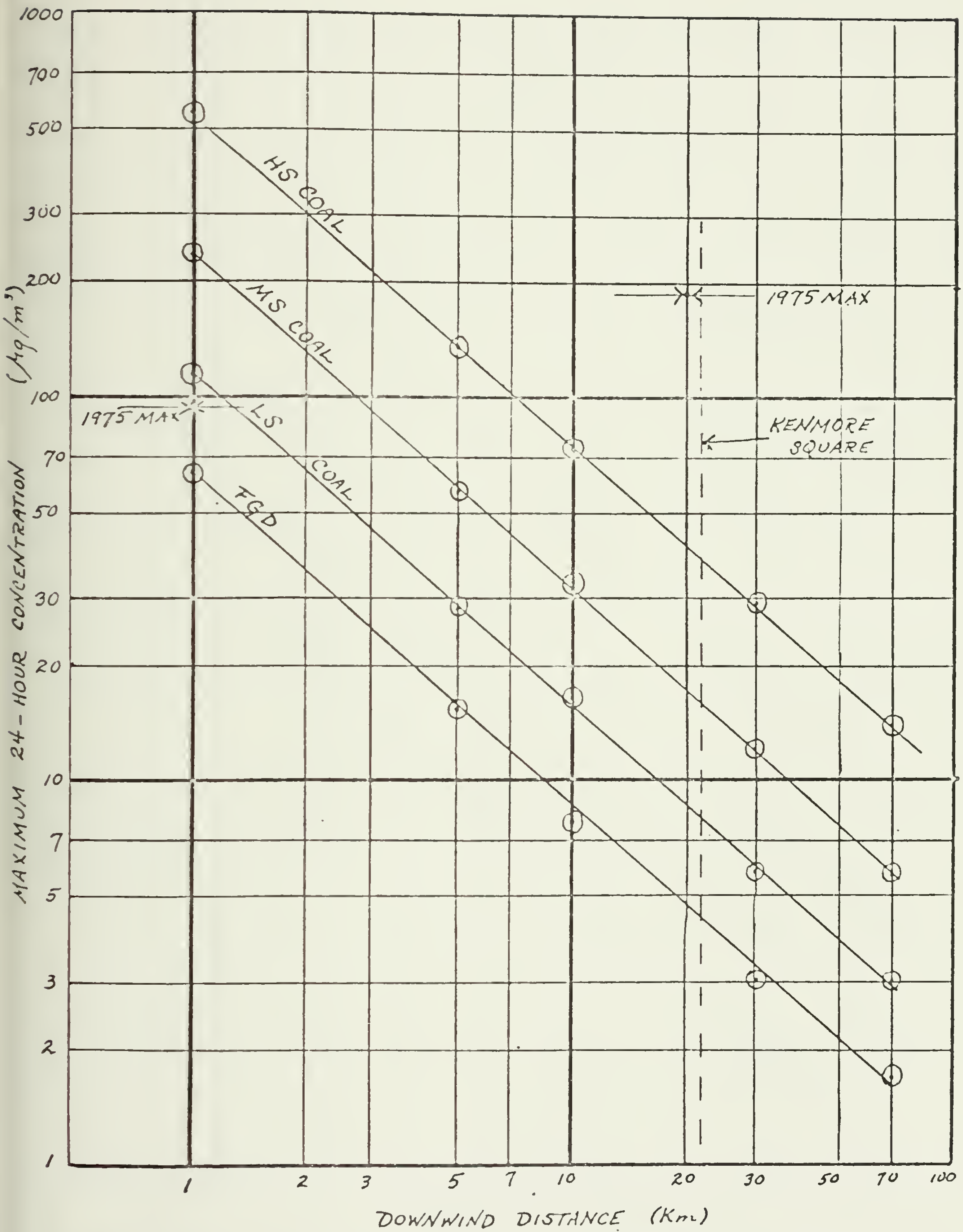


FIGURE 3.18 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS AS A FUNCTION of DOWNWIND DISTANCE. (1000 MWe PLANT)

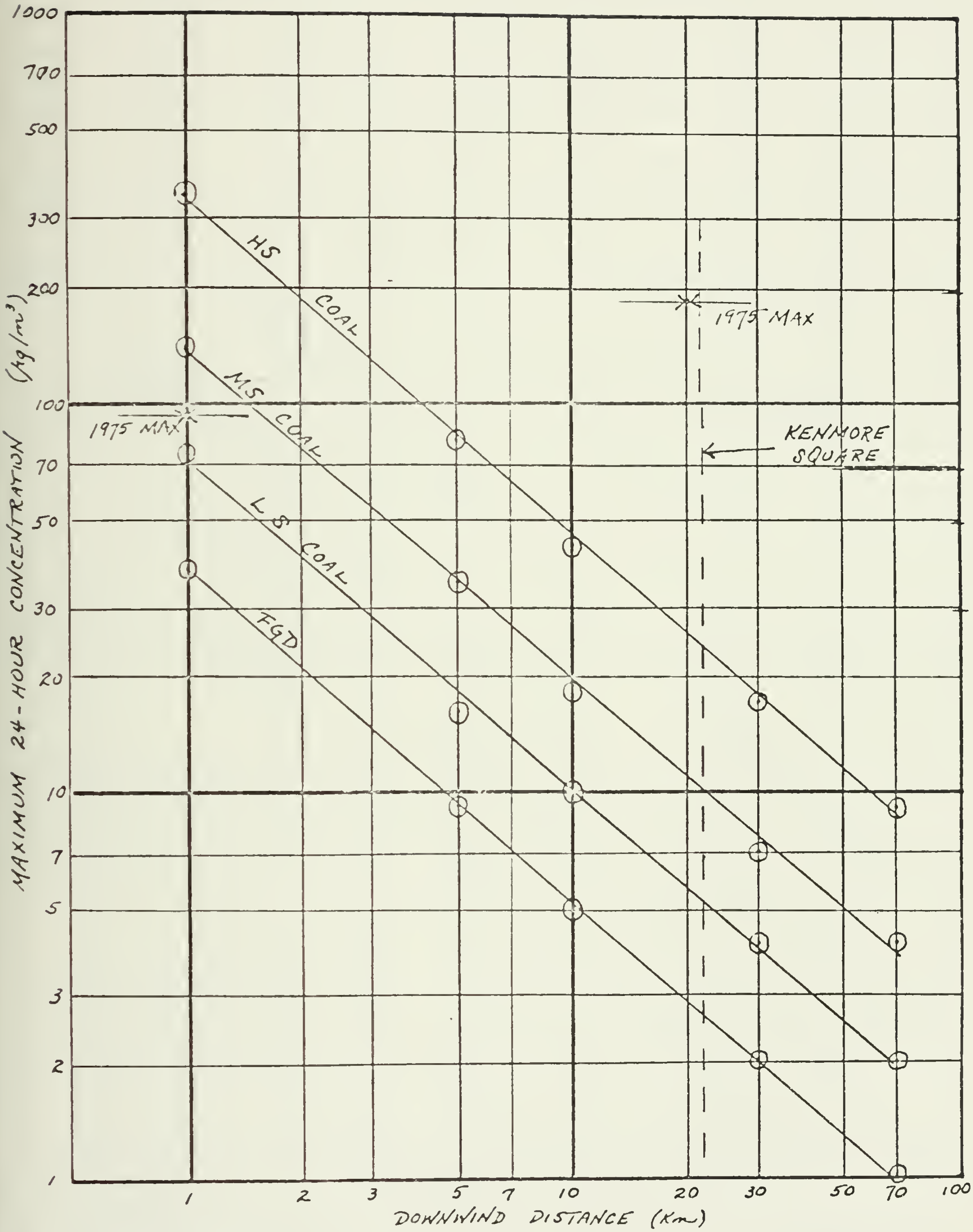


FIGURE 3.19 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS AS A FUNCTION of DOWNWIND DISTANCE. (500 MWe)

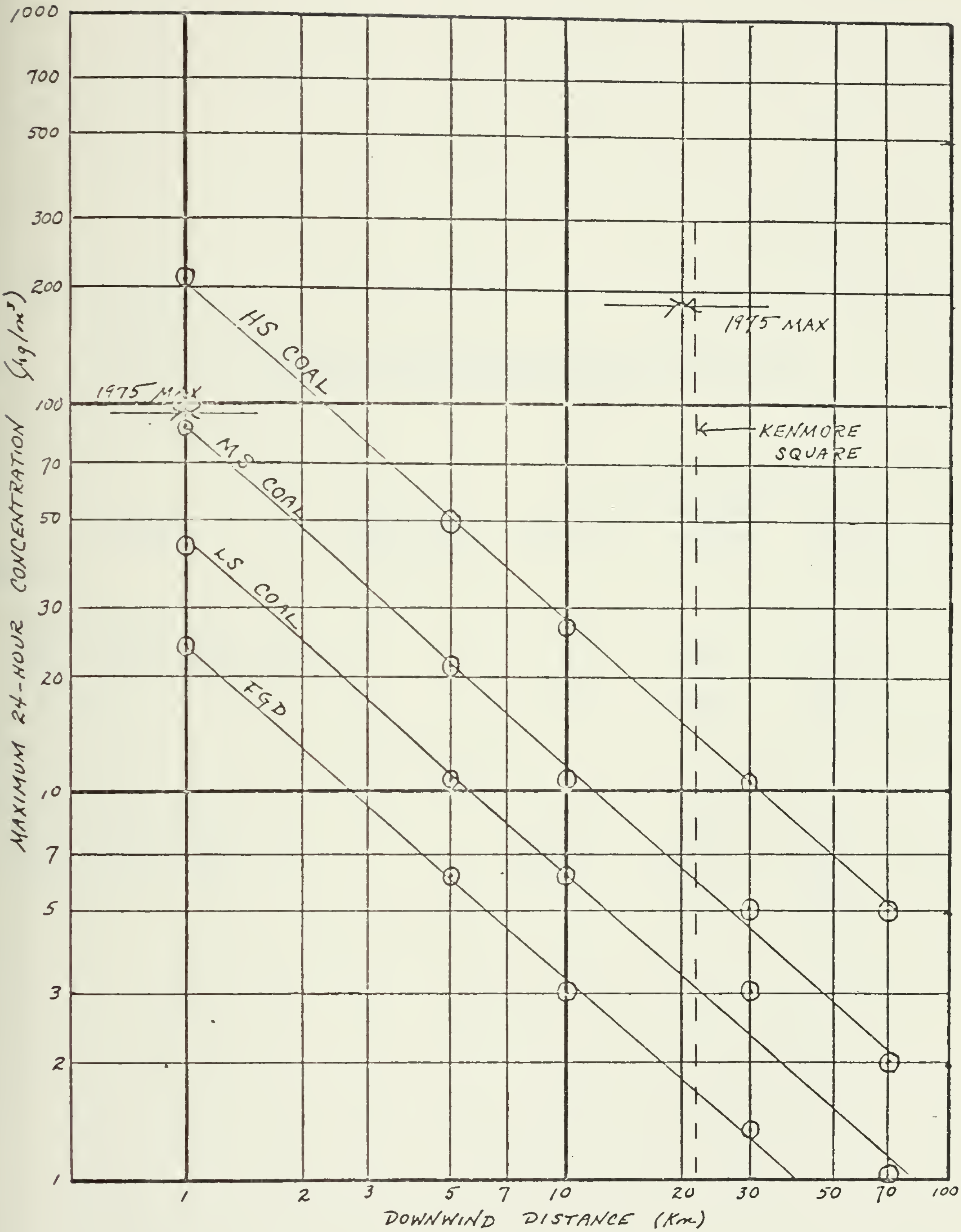


FIGURE 3.20 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS AS A FUNCTION of DOWNWIND DISTANCE. (200 MWe)

TABLE 3.32

IMPACT OF COAL-FIRED POWER PLANTS ON SO_2 CONCENTRATIONS IN SALEM AND AT KENMORE SQUARE

LOCATION	DISTANCE FROM PLANT	24-HOUR SO_2 CONCENTRATIONS ($\mu g/m^3$) 1000 MWe	500 MWe	200 MWe
SALEM	1 km			
1975 24-hour max		92	92	92
Power plant 24-hour max		65	39	24
Total 24-hour max		157	131	116
% Increase		71	42	26
KENMORE SQUARE	22 km			
1975 24-hour max		181	181	181
Power plant 24-hour max		4.5	2.5	1.6
Total 24-hour max		185.5	183.5	182.6
% Increase		2.5	1.4	0.9

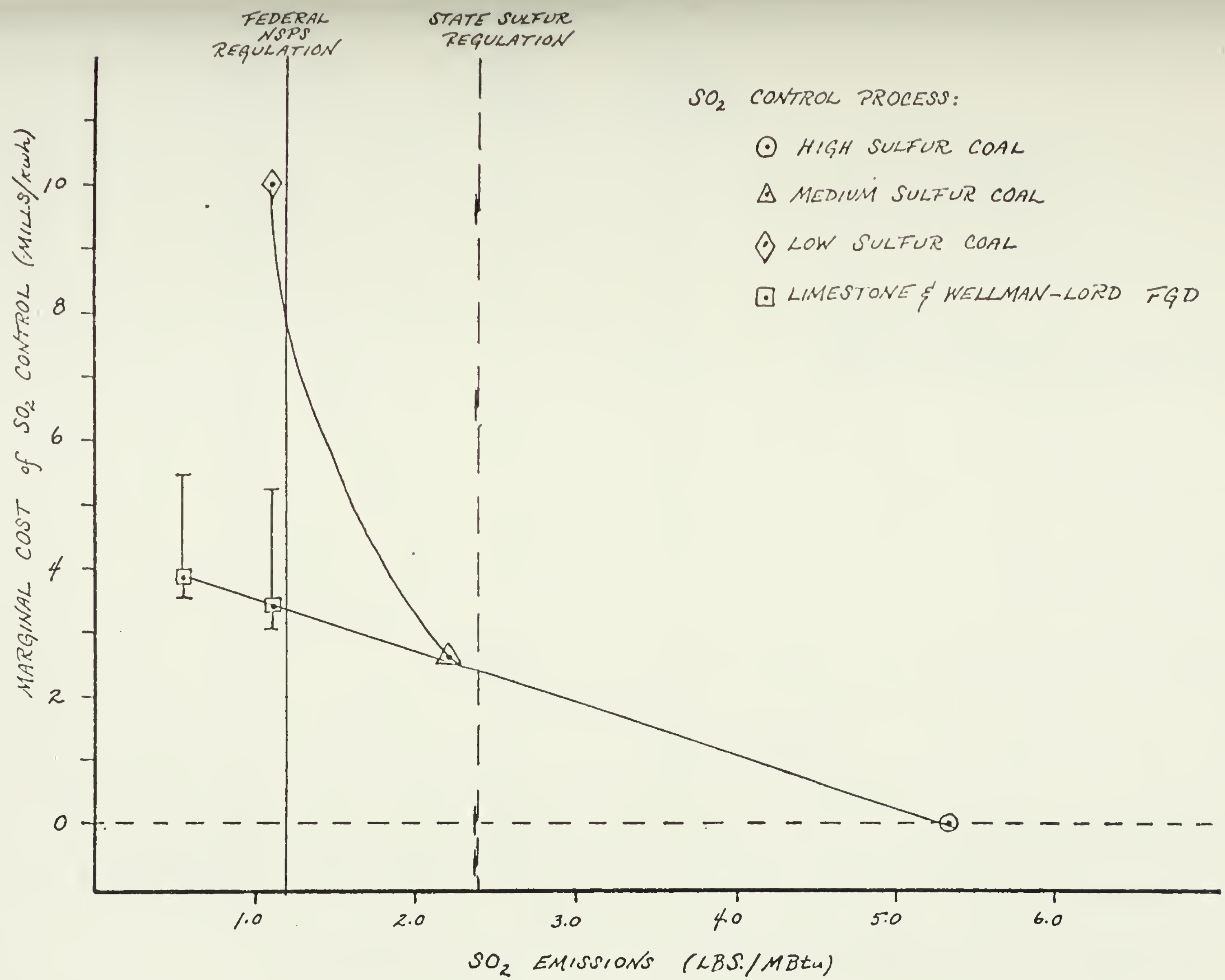


FIGURE 3.21 SO_2 EMISSIONS VERSUS COST of CONTROL FOR 1000 MWe COAL-FIRED PLANT (1978 $)

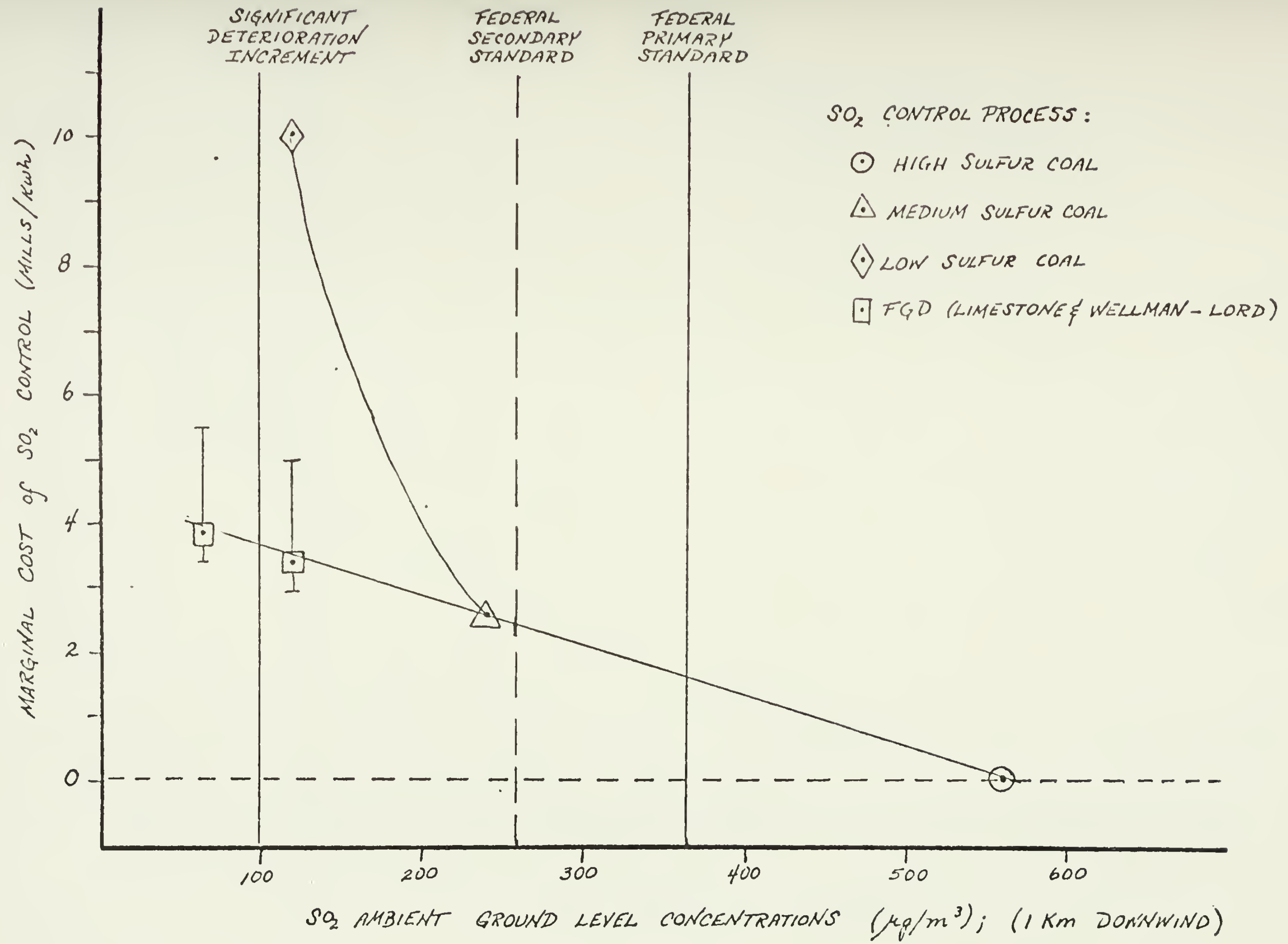


FIGURE 3.22 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS VERSUS COST of CONTROL FOR 1000 MWe COAL-FIRED PLANT. (1978 $)

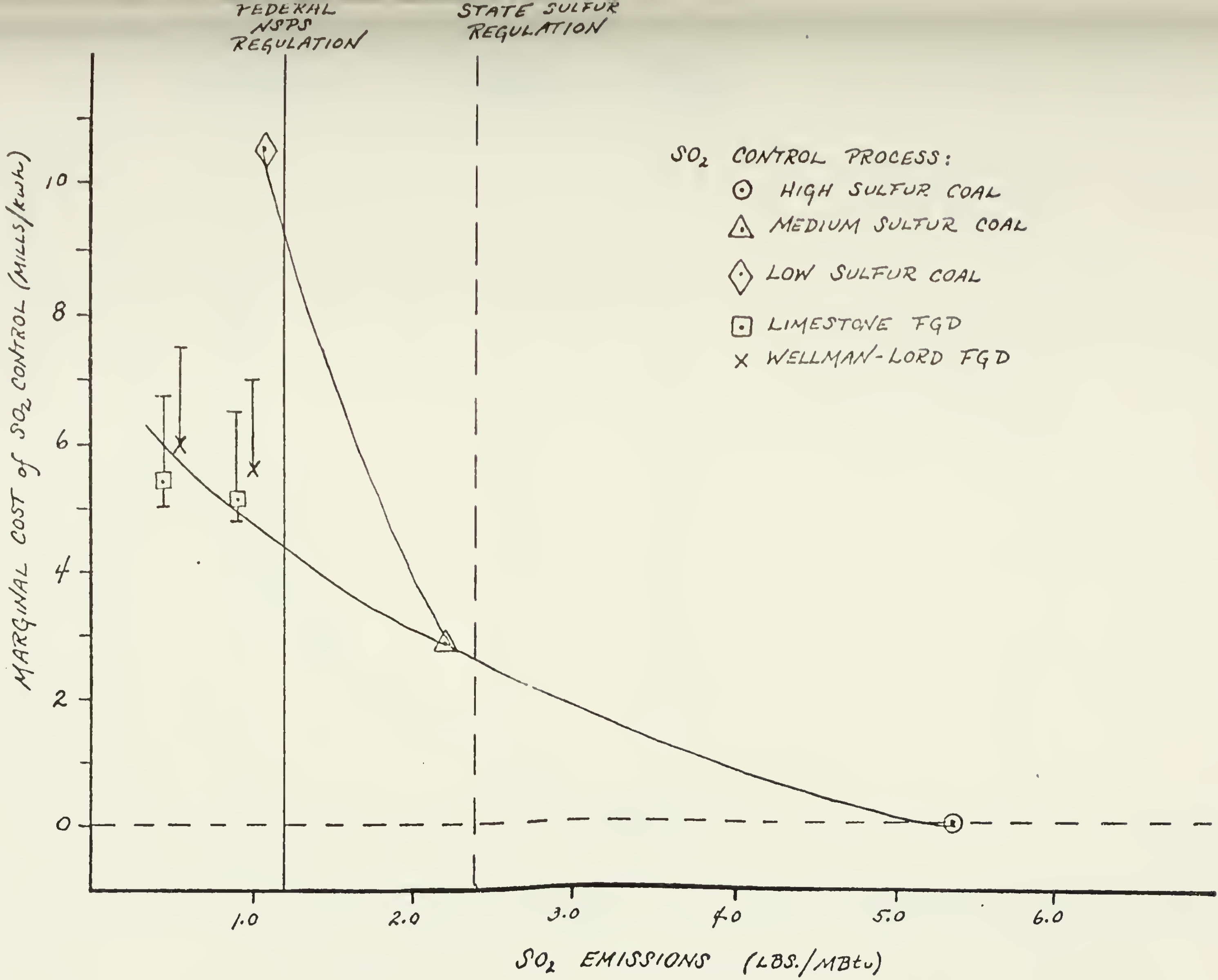


FIGURE 3.23 SO_2 EMISSIONS VERSUS COST of CONTROL FOR 500 MWe COAL-FIRED PLANT (1978 $)

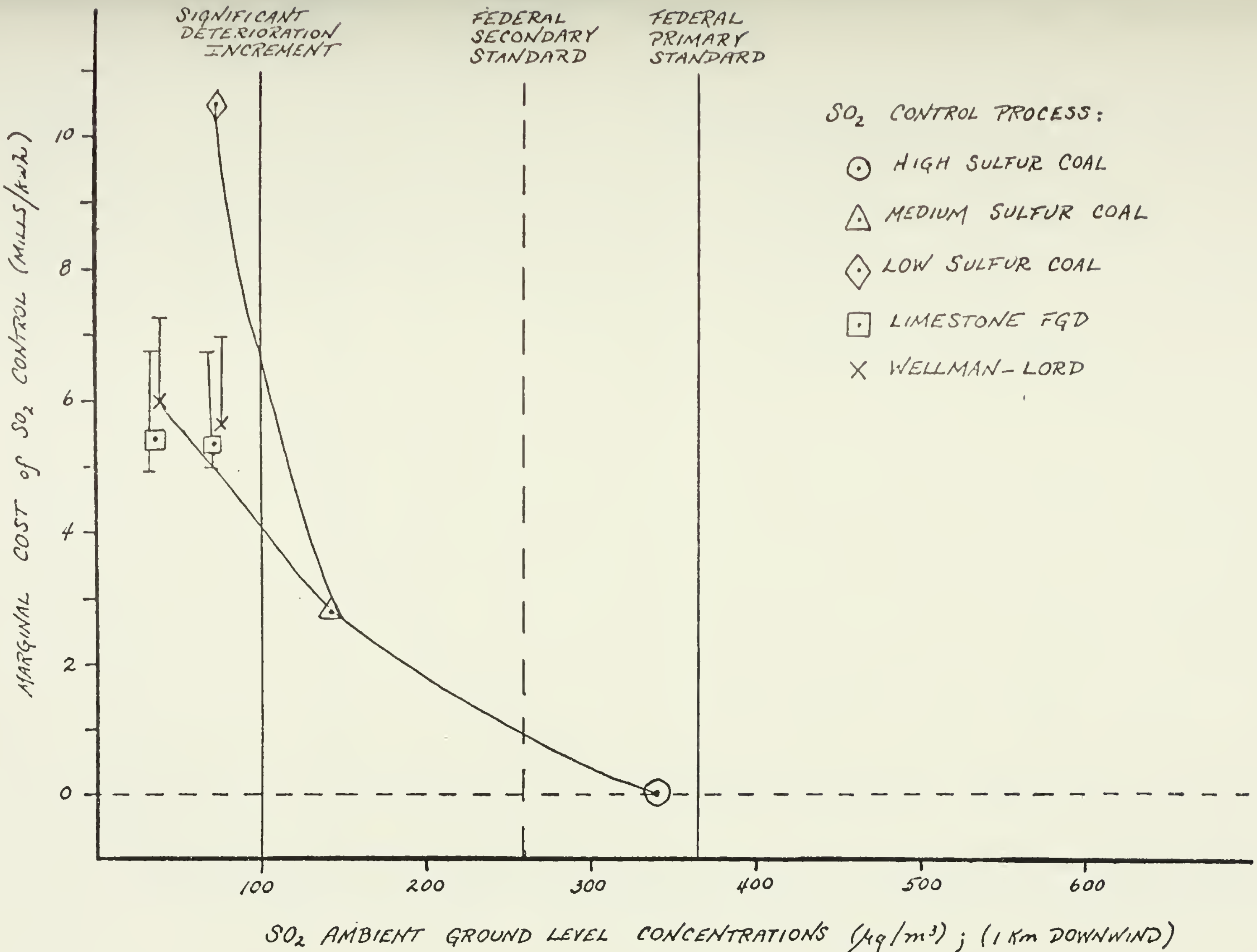


FIGURE 3.24 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS VERSUS COST of CONTROL FOR 500 MWe COAL-FIRED PLANT. (1978 $)

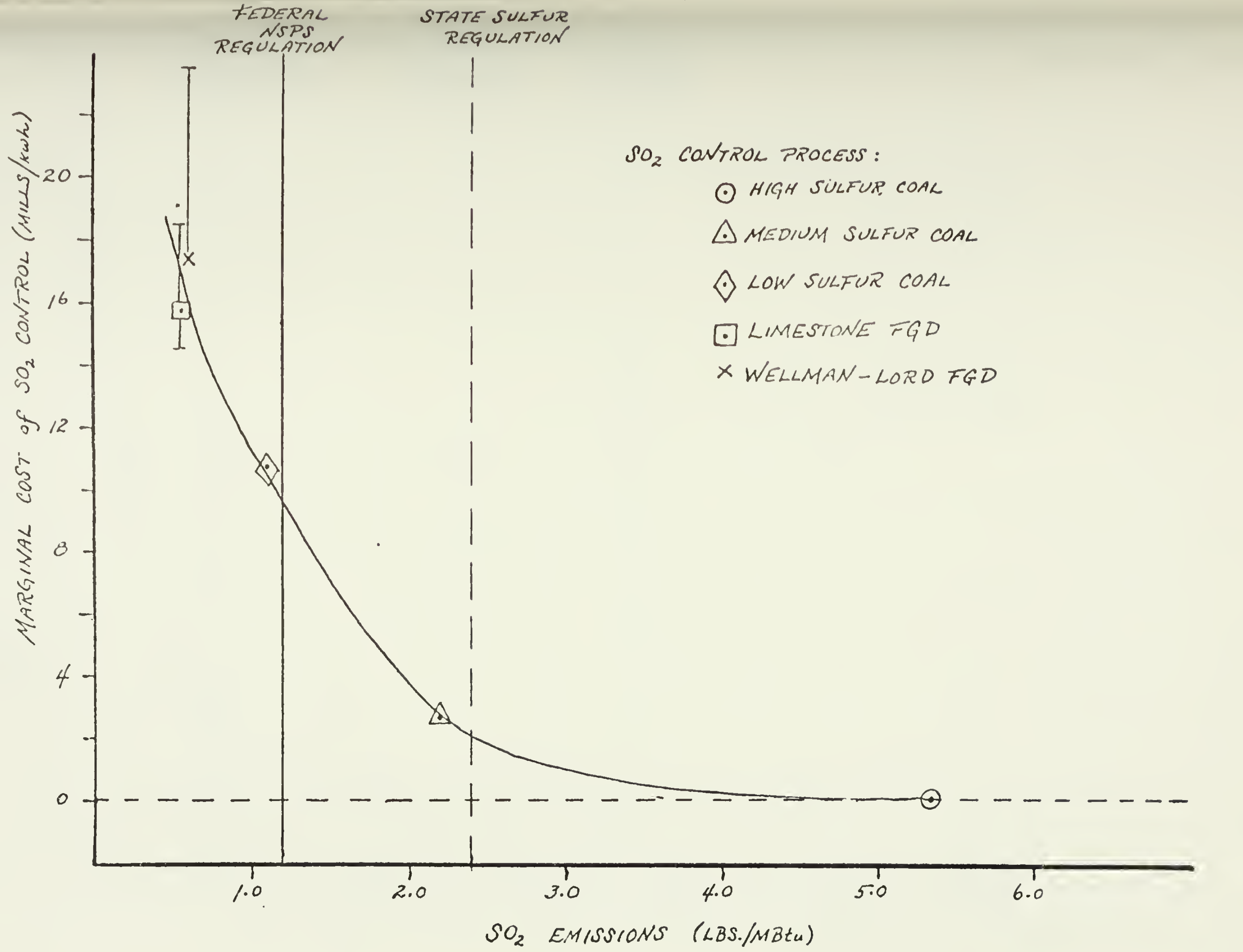


FIGURE 3.25 SO_2 EMISSIONS VERSUS COST of CONTROL FOR 200MWe COAL-FIRED PLANT (1978 $)

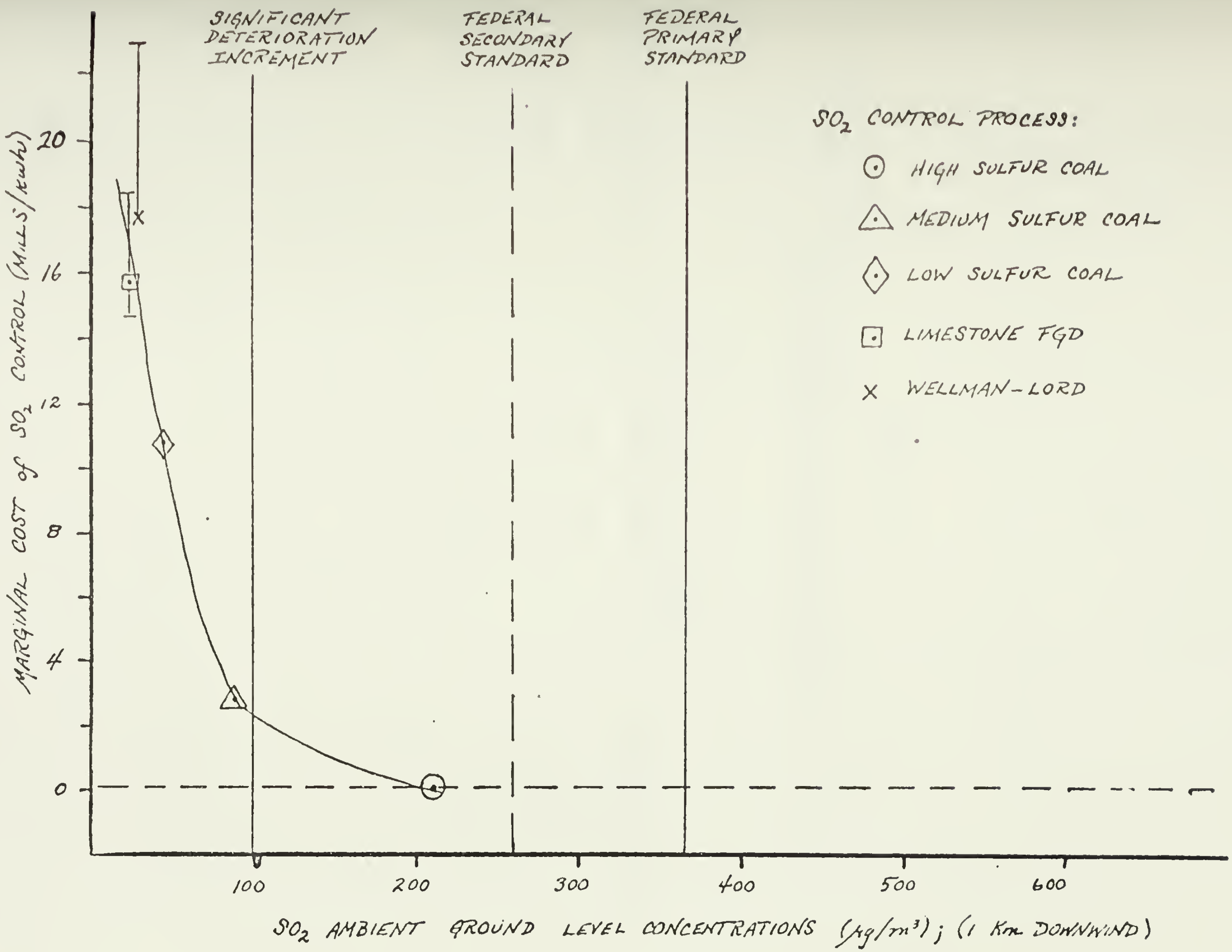


FIGURE 3.26 MAXIMUM 24-HOUR SO_2 CONCENTRATIONS VERSUS COST of CONTROL FOR 200 MWe COAL - FIRED PLANT. (1978 \$)

TABLE 3.33

MINIMUM COST OF SO_2 CONTROL TO MEET ALL APPLICABLE STANDARDS AS A FUNCTION OF POWER PLANT SIZE

PLANT SIZE (MWe)	MINIMUM COST OF CONTROL WHICH MEETS ALL STANDARDS (mills/Kwh)	TYPE OF CONTROL
1000 MWe	3.7 - 5.0	FGD
500 MWe	5.0 - 7.0	FGD
200 MWe	9.8 - 12.0	LS Coal

be the least cost alternative for the 200 MWe peak-load plant.

Nitrogen Oxides

Since it is not possible to specify the degree of nitrogen oxide control achievable in a particular boiler without actually operating the boiler at power, the emission rates specified in Table 3.2 will be the assumed rates for the proposed power plant. For the 1000 MWe plant, this will result in a 12 per cent increase in NO_x emissions above the metropolitan Boston baseline [Table 3.3], and in those terms NO_x will be the pollutant with the most significant impact on ambient air quality.

The only air quality standard applicable to NO_x is an annual arithmetic mean for the ambient concentration. Without using wind rose data, as previously discussed, the annual average resulting from the proposed power plants cannot be estimated. However, the maximum 24-hour NO_x concentration can be estimated. Nitrogen oxide emission rates for the three plants are as follows:

EMISSION RATES (g/sec)

	1000 MWe	500 MWe	200 MWe
w/o FGD	790	409	169
w/ FGD	811	420	173

The maximum NO_x concentrations as a function of downwind distance are listed in Table 3.34. None of the maximum 24-hour concentrations of NO_x exceed even the annual ambient standards. The annual average concentrations would be a small fraction of the maximum 24-hour concentration. The most that can be stated about NO_x emissions from the proposed power plants is that the incremental addition to ambient concentrations will be considerably

TABLE 3.34

MAXIMUM 24-HOUR CONCENTRATIONS OF NITROGEN OXIDES FROM COAL-FIRED POWER PLANT

DISTANCE DOWNWIND (km)	24-HOUR NO_x CONCENTRATIONS ($\mu g/m^3$) 1000 MWe w/o FGD	1000 MWe w/ FGD	500 MWe w/o FGD	500 MWe w/ FGD	200 MWe w/o FGD	200 MWe w/ FGD
1.0	76	88	46	53	29	33
5.0	18	21	11	12.7	6.8	7.9
10.0	9.8	11.4	6	6.9	3.7	4.3
30.0	4.0	4.5	2.4	2.8	1.5	1.7
70.0	2.0	2.2	1.2	1.4	0.7	0.8
MAXIMUM 24-HOUR ($\mu g/m^3$)	76	88	46	53	29	33

below the standard. By themselves, the NO_x emissions from the power plants will result in no violations of standards. There are no significant deterioration increments applicable to NO_x emissions with which to compare the power plant emissions. There is assumed to be no marginal cost associated with the NO_x emission control.

3.5 Summary

The total marginal costs of air pollution control for each of the plant capacities are displayed in Table 3.35. These costs represent the minimum estimated costs of control sufficient to satisfy all applicable air pollution standards and regulations.

TABLE 3.35

TOTAL MARGINAL COST OF AIR POLLUTION CONTROL FOR COAL-FIRED POWER PLANTS (1978 $)

	1000 MWe	500 MWe	200 MWe
Particulate control (99.5% collection)	0.57	0.82	2.0
Sulfur oxides control (90% removal)	3.2 - 5.0	5.0 - 7.0	9.8 - 12.0
Nitrogen oxide control	0.00	0.00	0.00
TOTAL (1978 $)			
mills/KWh	4.27 - 5.57	5.82 - 7.82	11.8 - 14.0
¢/MBtu	48 - 62	63 - 85	127 - 151
$/ton of coal	12.00 - 15.50	15.75 - 21.25	31.75 - 37.75

FOOTNOTES Chapter 3

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Commerce Technical Advisory Board, Report on Sulfur Oxide Control Technology (Washington, D.C.: U.S. Department of Commerce, 1975).

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53. M. Granger Morgan, et al., "The Social Costs of Producing Electrical Power From Coal: A First Order Calculation," Proceedings of the IEEE, Vol.61 (October, 1973), p. 1439.

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CHAPTER 4. ECONOMIC ANALYSIS OF COAL-FIRED ELECTRIC POWER GENERATION

The cost components of coal-fired electric power generation which will comprise the estimated busbar cost of electricity are capital costs, fuel costs including coal transportation, non-fuel operating and maintenance costs, and pollution control costs. The busbar power generation costs is used to denote costs computed at the plant busbar, the point at which the plant's output is fed into the utility power system. The busbar cost excludes other power system costs components such as transmission and distribution costs. These costs need not be considered in this analysis since they will not vary significantly among the various generation alternatives.

4.1 Coal-Fired Electric Power Plant Capital Costs

In order to be of most value to policymakers, capital cost estimates should be specific, particularly with respect to parameters such as the power plant design basis and size, plant location, assumed cost escalation and interest rates, and the year to which costs are referenced. Explicitly identifying these parameters in the cost estimate permits discussion and possible revision of specific aspects of the estimate when additional or better information becomes available, and it also permits persons who disagree with the estimate to identify the reasons for disagreement.

The Oak Ridge National Laboratory (ORNL) has developed a computer code for preparing electric power plant capital cost estimates as a function of the parameters mentioned above. The computer code is entitled CONCEPT for "computerized conceptual cost estimates for steam-electric power plants"[35]. The procedures used on CONCEPT are based on the assumption that any central station power plant of the same type involves approximately the same major

cost components, regardless of location or date of initial operation. The code estimates these major cost components as a function of time, plant type, and size for a reference plant which then can be adjusted to fit any case of interest. The reference case for each plant type (pressurized water and boiling water reactor nuclear stations, coal, oil and gas-fired fossil-fuel stations) was developed from detailed cost estimates for a hypothetical 1000 MWe power plant prepared by United Engineers & Constructors, Inc. [86]. The reference plants were assumed to be located at a hypothetical site called Middletown. This site is assumed to be favorable for a power plant location in all respects, including an adequate supply of cooling water, low population density, satisfactory transportation facilities, and a sufficient labor supply for a 40-hour workweek [87].

The direct capital costs for the reference plant are divided into two-digit cost account categories as follows:

ACCOUNT NUMBER	ACCOUNT TITLE
10	Land and land rights
11	Structures and site facilities
12	Boiler plant equipment
13	Turbine plant equipment
14	Electric plant equipment
15	Miscellaneous plant equipment

The reference plant costs may be adjusted to various plant sizes through the use of cost-size scaling functions for each of the two-digit cost accounts. Cost data files containing 12 years of historical data on labor rates, equipment costs, and material costs for 23 United States cities, including Boston, are used to translate capital cost estimates from the reference year and location to the desired year and location. This is done

by separating each two-digit direct cost account into labor, equipment, and material components and multiplying these components by the appropriate ratio or projected cost indicies for the new location and year to the 1971 cost indicies for Middletown [Figure 4.1].

The general flow of calculations in the CONCEPT code is indicated in Figure 4.2. A more detailed description of the code is available in ORNL-4809 (see note 84).

The parameters input to CONCEPT for this analysis are listed below:

Net plant electrical capacity = 1000, 500, and 200 MWe;

Plant type = coal-fired, no SO_2 removal, natural draft cooling towers;

Plant location = Boston, Massachusetts;

Date of beginning of design and construction = January, 1978

Length of commercial operation = January, 1985;

Length of workweek = 40 hours, no overtime;

Interest rate = 8 per cent simple interest;

Costs referenced to beginning of construction, 1978, and escalated to start of commercial operation, 1985.

A detailed breakdown of the capital cost estimate into five-digit accounts for the 1000 MWe plant as printed by the CONCEPT code is included in Appendix H. Captial cost summaries for each of the three plant sizes are listed in Table 4.1. Based on historical cost data through 1974, the code escalated costs from 1974 to 1978 and during construction at 8.1 per cent annually to arrive at the start of commercial operation cost.

The cost estimates are sensitive, of course, to the assumed cost escalation and interest rates. The approximate effect of small changes in these parameters are as follows:

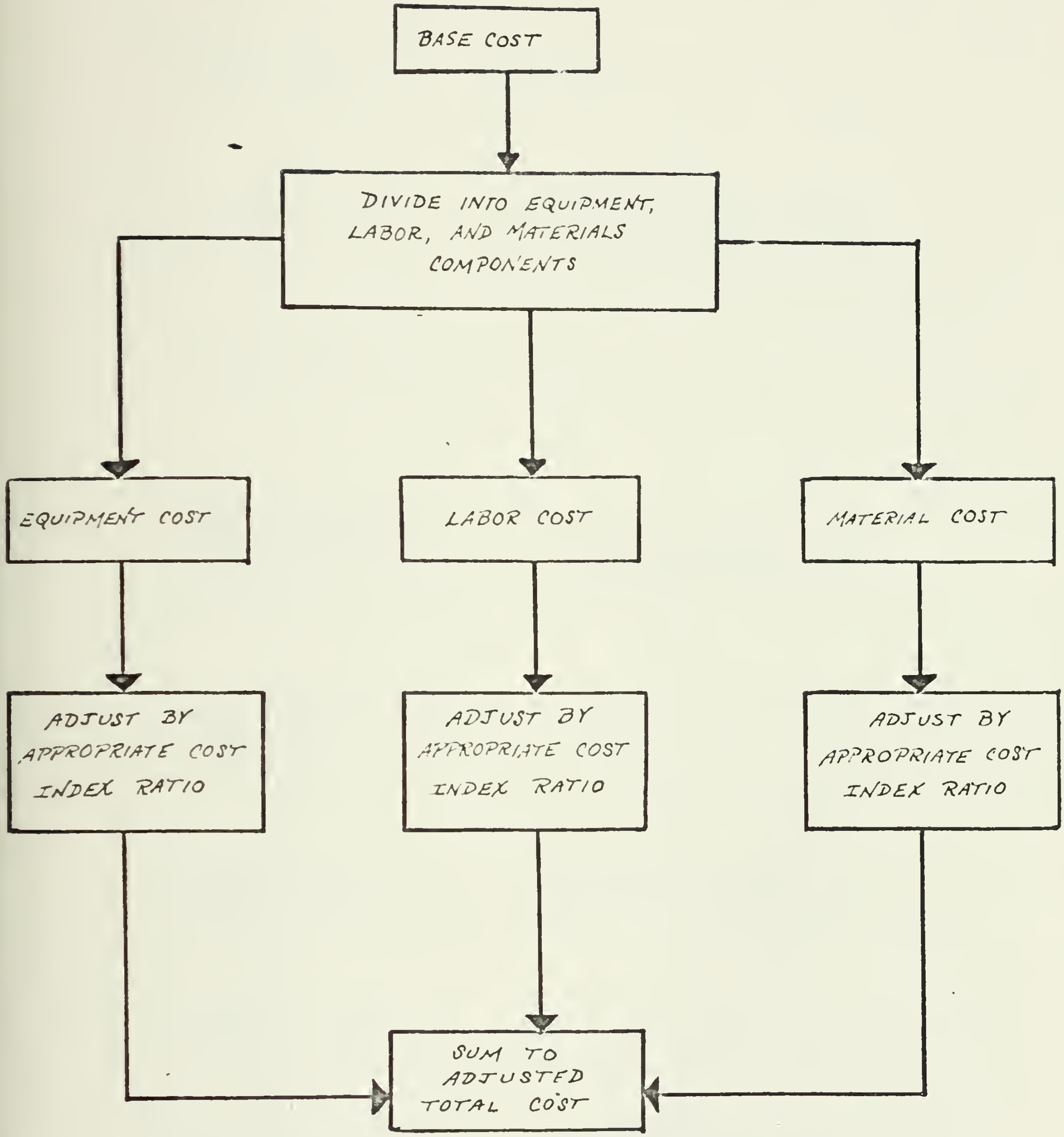

FIGURE 4.1 METHOD USED TO ADJUST BASE COSTS IN <u>CONCEPT</u>

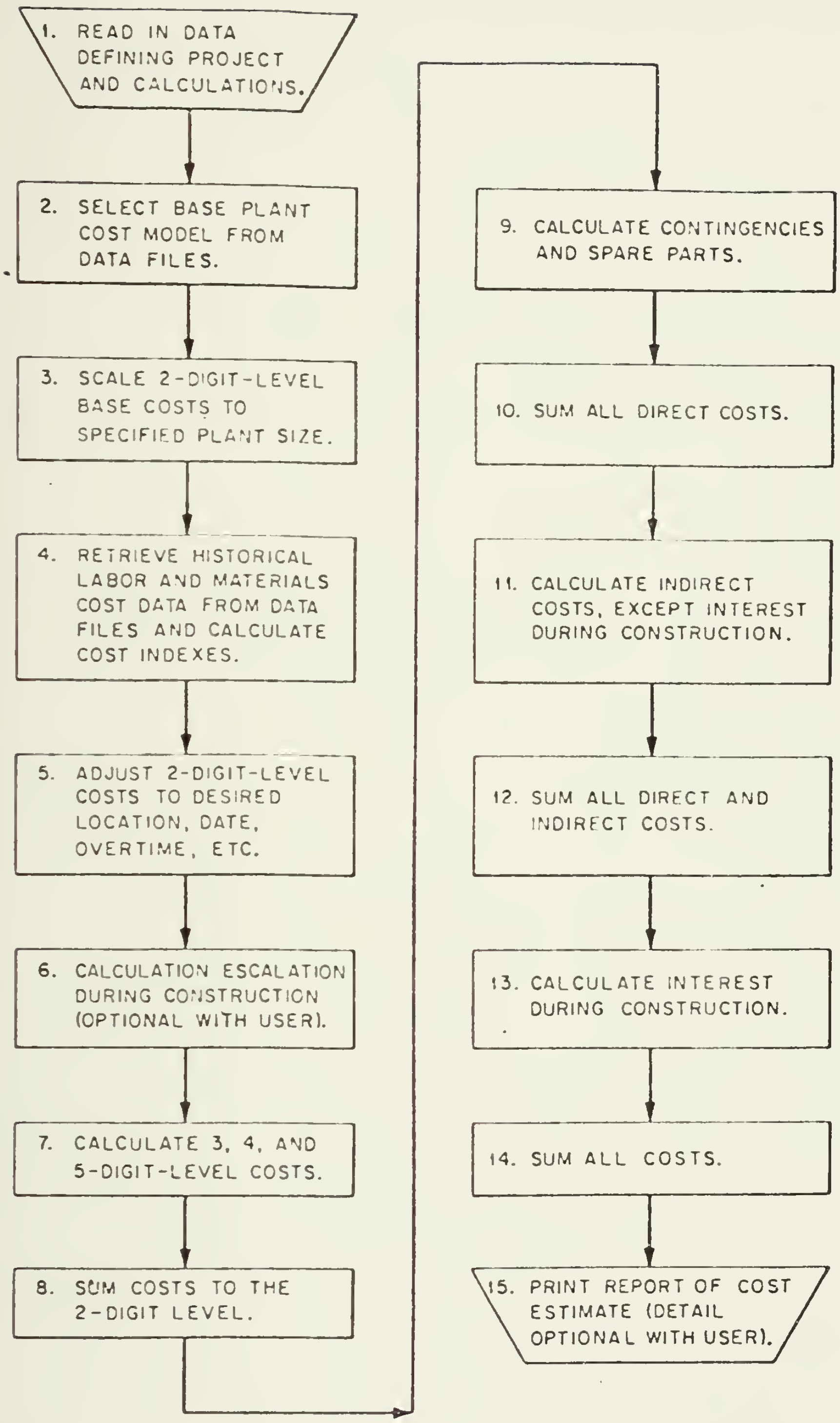

Figure 4.2 CONCEPT — general flow of calculations.

TABLE 4.1

…AL COST ESTIMATES FOR A NEW COAL-FIRED POWER PLANT LOCATED IN BOSTON, MASSACHUSETTS (NO SO_2 REMOVAL; BEGIN CONSTRUCTION 1978; BEGIN COMMERCIAL OPERATION 1985)

ACCOUNT	1000 MWe	500 MWe	200 MWe
	Direct Costs, thousands of dollars		
…d Land Rights	1,000	1,000	1,000
… Plant			
…uctures and site facilities	40,070	24,063	12,103
…ler plant equipment	101,303	54,278	23,798
…bine plant equipment	98,696	51,517	24,571
…ctric plant equipment	21,378	15,650	10,362
…cellaneous plant equipment	6,173	5,014	3,809
Subtotal	259,019	150,530	74,823
…re parts allowance	1,516	875	430
…tingency allowance	18,320	10,676	5,331
Subtotal	278,855	162,082	80,584
*****	Indirect Costs, thousands of dollars		
…tion Facilities, Equip-…d Services	15,994	11,572	8,877
…ring and Construction …nt Services	24,594	16,489	11,211
…osts	9,370	6,421	4,531

Interest During Construction	95,338	57,375	31,206
Subtotal	145,296	91,857	55,825
*****		Total Capital Costs	
START OF CONSTRUCTION COST (1978)			
thousands of dollars	425,151	254,939	137,409
$/KW	425	510	687
Escalation During Construction (8.1 %/yr)			
thousands of dollars	119,228	69,109	33,923
START OF OPERATION COST (1985)			
thousands of dollars	544,379	324,048	171,332
$/KW	544	648	857

Change of 1% in:	Start of Construction Costs (1978)	Start of Operation Costs (1985)
Escalation of Costs 1974 - 1978 (8.1%)	3.8	3.8
Escalation of Costs During Construction, 1978 - 1985 (8.1%)	-----	3
Interest During Construction (8.0%)	2	2

Recognizing the uncertainty of these parameters and the tendency of cost estimates to be lower than the actual cost, the capital cost estimates will be assumed to have a low variant 5 per cent below the CONCEPT estimate for the 1978 and 1985 costs and a high variant 10 per cent above the beginning of construction estimate and 15 per cent above the start of commercial operation cost. Thus, the range of capital cost estimates for each plant size are as presented in Table 4.2 and Figure 4.3.

A comparison of the capital cost estimates generated by the CONCEPT code and other estimates in the literature adjusted to 1985 dollars is shown in Figure 4.4. The A.D. Little estimate [88] was the only estimate made specifically for a coal-fired plant to be located in New England and it is in close agreement with the CONCEPT estimates. The estimates by Davis, Phung, and Lee [89] are all higher than the CONCEPT estimates, but appear to have been erroneously calculated. To wit, each of these estimates escalated either 1974 or 1975 cost estimates to 1984 or 1985 by assuming an annual inflation rate i, and multiplying the 1974/1975 estimate by $(1 + i)^{10}$. In this manner, assuming a 6 to 8 per cent inflation rate, costs would be approximately doubled by 1985. However, this method of estimating cost escalation is incorrect if applied to a plant which is to begin operation in 1985. Construction on such a plant would begin in 1978, and funds would be

TABLE 4.2

RANGE OF CAPITAL COST ESTIMATES FOR A NEW COAL-FIRED POWER PLANT WITH NO SO_2 REMOVAL

	CAPITAL COST ($/KW)		
PLANT SIZE	LOW VARIANT	BEST ESTIMATE	HIGH VARIANT
START OF CONSTRUCTION (1978)			
200 MWe	653	687	756
500 MWe	485	510	561
1000 MWe	404	425	468
START OF OPERATION (1985)			
200 MWe	814	857	985
500 MWe	616	648	745
1000 MWe	517	544	625

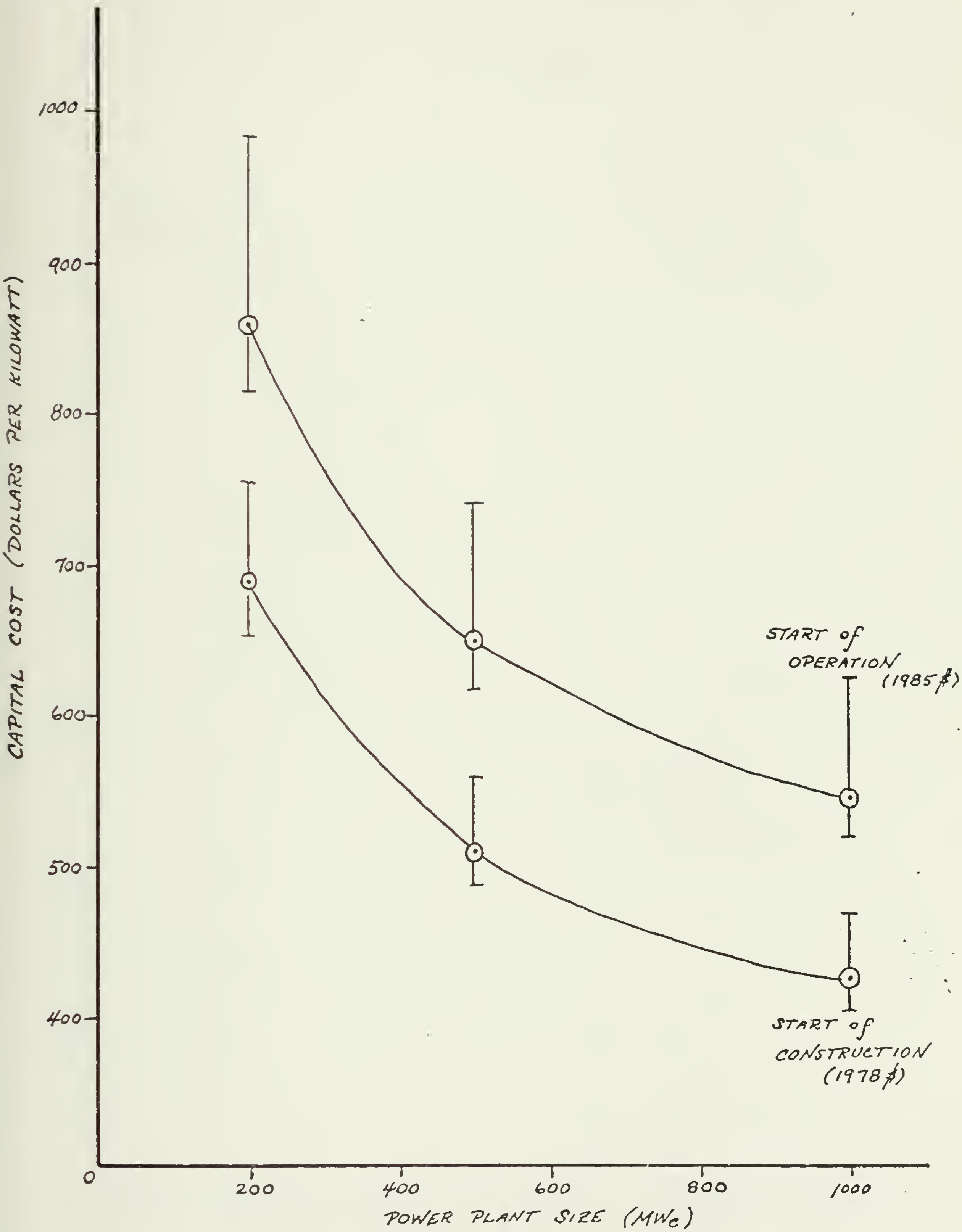

FIGURE 4.3 CAPITAL COST ESTIMATES FOR NEW COAL-FIRED POWER PLANT IN BOSTON, MASSACHUSETTS. (NO SO_2 REMOVAL)

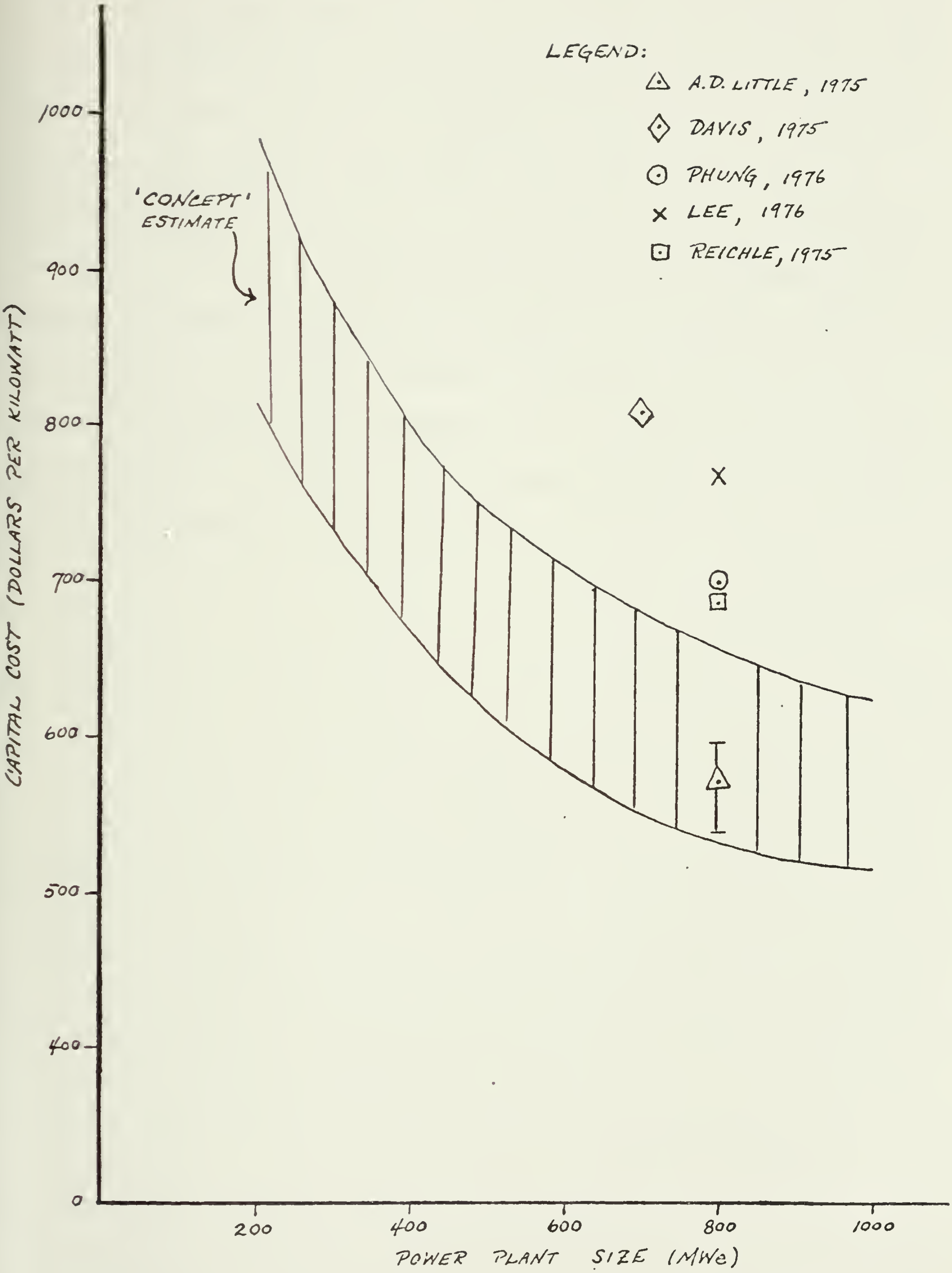

FIGURE 4.4 COMPARISON of CAPITAL COST ESTIMATES FOR NEW COAL-FIRED POWER PLANT IN BOSTON, MASSACHUSETTS. (NO SO_2 REMOVAL) (1985 $)

expended continuously over the period 1978 - 1985 as represented by a cash-flow curve (see CONCEPT print-out in Appendix H, for example). Costs incurred and paid for prior to 1985 should not be escalated to that year. In fact, as an examination of the CONCEPT data will show, an 8.1 per cent escalation rate applied to construction from 1978 - 1985 results in a 28 per cent increase in costs, not a 71 per cent increase (escalating by $(1 + .081)^7 = 1.71$). Correcting for this error in cost escalation, the estimates by Davis, Phung and Lee correspond to the CONCEPT estimates. The estimate made by Reichle [90] contains no explanation as to how it was obtained. The CONCEPT estimates appear to be representative of projected coal-fired power plant capital costs and will be the capital cost estimates used in this analysis.

4.2 Fuel Costs

The two major components of utility fuel costs, coal price and coal transportation costs, will be estimated in this analysis. The purchased coal is assumed to be a high Btu, bituminous coal mined in Westmoreland County, Pennsylvania [see Figure 2.2]. The use of low-Btu, low sulfur Western coal at the proposed power plants will not be considered here.

4.2.1 Projected Coal Prices, F.O.B. at the Mine

The U.S. coal market was chaotic in the period 1973 to 1975 following the OPEC oil embargo. The base contract price for the high sulfur Eastern steam coal increased from $8.50 per ton in 1973 (F.O.B. mine) to over $30.00 per ton in the spring of 1974, while spot prices for coal were on the order of $50.00 per ton. Two factors contributed to the coal price increases. The sudden increase in oil prices, in conjunction with the embargo, created a surge in demand for coal which exceeded the capacity of the coal industry to expand production. Also, coal producers anticipated future production cost increases, particularly labor cost increases associated with federal mine safety regulations. Since that period, as the coal industry has adjusted to the new demand levels, coal prices have declined from their record high levels of early 1975, though they have remained substantially higher than before the oil embargo [91]. Future coal prices must be estimated in terms of this stabilized coal market.

It is of little value in this analysis to make detailed estimates of future coal prices based on projected coal production cost changes as some recent studies have done [92]. Over the operating life of the plant there are too many parameters affecting coal prices resulting in too much uncertainty

to make precise estimates meaningful. Rather, the approach here will be to use estimates of late 1975 coal prices under long-term contract to electric utilities as a baseline and to assume that future coal prices will remain within 10 per cent of this baseline in real (non-inflated) dollars. In other words, coal prices will be assumed to increase monotonically at approximately the general inflation rate. Making this assumption does not solve the problem of uncertainty for the policymaker, but it does constrain the uncertainty. It is unlikely, in light of historical trends for other depletable resources, that coal prices will decline significantly below current levels. The policymaker could assume, with a high degree of confidence, that actual future prices will be equal to or greater than the 1975 price in real dollars.

As discussed in the previous chapter (Section 3.3.2.2), the coal prices assumed in this analysis will be those estimated in 1976 by the Center for Energy Policy [93]. These prices F.O.B. at the mine, as a function of sulfur content, are as follows:

	1975 $	1978 $
Low sulfur (0.7%)	173 ¢/MBtu 43.25 $/ton	206 51.50
Medium sulfur (1.5%)	100 ¢/MBtu 25.00 $/ton	119 29.75
High sulfur (0.7%)	75 ¢/MBtu 18.75 $/ton	89 22.30

Other recent estimates of Eastern high sulfur coal prices, F.O.B. at the mine, include:

A.D. Little/S.M. Stoller (1974 $) - 30.00 $/ton [94]

T.H. Lee (1975 $) - 23.50 $/ton [95]

Corey (1975 \$) - 22.00 \$/ton [96]

Zimmerman (1975 \$) - 14.00 \$/ton [97]

It seems clear that actual high sulfur coal prices are lower in 1976 than the 1974 estimate of A.D. Little which was made while the coal industry was still adjusting to increased demand. The CEP estimate of \$18.75 per ton appears to be reasonable based on the remaining estimates.

4.2.2 Coal Transportation Costs

The closest coal fields to Salem, Massachusetts, are in southwestern Pennsylvania, a distance of approximately 650 miles. The transportation of coal from Westmoreland County to Salem will be assumed by be by railroad. In actuality, since Salem is located on a harbor, it is possible that coal would be transported by rail to a port in New York, New Jersey, or Connecticut, and then transferred to barges for the remainder of the trip to Salem. However, this mode of transportation will not be evaluated.

The least expensive mode of railroad transportation of coal would be by unit trains. The term "unit train" applies to a classification of service by the railroads which can be distinguished from other forms of service in two ways: (1) it is a specialized train, more or less permanently coupled together, and operated in a shuttle movement from a point of origin to a point of destination on a fixed and disciplined basis, and (2) the commodity to be shipped must be in sufficient quantity to enable a complete train to be moved from the point of origin to the point of destination without the need for classification (the process of selecting and organizing individual carloads into trains at switching yards enroute to the destination). A service contract for unit train coal shipments typically specifies a minimum

tonnage per train, a minimum annual tonnage, number of points of origin and destination permitted, and a timetable schedule including turn-around time at the destination. The raison d'etre for unit train service is large potential cost savings in comparison with carload or multiple-car service. Savings are available through improved equipment utilization and reduced costs of train operation due to lesser switching and classification costs.

There is very little current data available on unit train rates to New England. The only unit train operating to the region in 1976 transported coal from Westmoreland, Pennsylvania, to Concord, New Hampshire, and the Bow electric power plant of the Public Service Company of New Hampshire. Bituminous coal rates to all other points in New England have been cancelled by the railroads.

In order to estimate the magnitude of rates which might be obtained in 1976, unit train rates which were available in 1967 to several New England points were adjusted to 1976. The escalation factor was calculated by comparing the change in rates to destinations where rates were available in both 1967 and 1976. These destinations are Albany, New York, which approximates a location in western New England, and Concord, New Hampshire. Rates were obtained from the Clearfield and Westmoreland coal districts in western Pennsylvania. The results for a unit train with a 7,000 ton minimum shipment in carrier-owned equipment from one or two origins are given below: [98]

Ex Parte Bituminous Coal Unit Train Rates To New England

ORIGIN	DESTINATION	1967 RATE ($/ton)	1976 RATE ($/ton)	% INCREASE
Clearfield	Albany, N.Y.	3.75	7.99	113
Westmoreland		3.97	8.43	112

Clearfield	Concord, N.H.	4.67	9.77	113
Westmoreland		4.84	10.18	108

The escalation factor for rates from 1967 to 1976 is approximately 110 per cent, which is equivalent to 8.6 per cent increase per year. Unit train rates were not extant for either Salem or Boston in 1967, but were available for Worcester and Springfield, Massachusetts, as well as Concord, New Hampshire. The estimated 1976 rates to these locations from Westmoreland County are listed below:

TABLE 4.3

ESTIMATED EX PARTE BITUMINOUS COAL UNIT TRAIN RATES FROM WESTMORELAND COUNTY, PENNSYLVANIA

DESTINATION	1967 RATE ($/ton)	ESTIMATED 1976 RATE ($/ton)	ESTIMATED 1976 RATE (c/MBtu)
Springfield, MA	4.62	9.70	39
Worcester, MA	4.74	9.95	40
Concord, NH	4.89	10.18	41

Thus, on the basis of historical ex parte rates, projected unit train rates from Westmoreland County to Salem in 1976 would be approximately $10.00 per ton, or 40 cents per MBtu.

An ex parte rate does not reflect the results of a railroad-utility bargaining process. Rather, it is an unilateral estimate of the rate by the railroad. The actual rate obtained by a shipper is arrived at through contract negotiations with the railroad. In the case of coal transportation to electric utilities, the railroad and the utility possess a degree of monopoly and monopsony power in their respective markets. A utility would be monopsonistic with respect to the railroad, particularly in New England

because it would be the major purchaser of coal in the local coal market. In addition, the utility would possess bargaining power to the extent that it has other fuel options available. The railroad, of course, offers one of a very few means of delivering large-volumes of coal to the utility. Therefore, one would not expect that the result of the bargaining process would resemble the result of a competitive process. However, the outcome of such contract negotiations cannot be estimated at this time, and thus the ex parte rates must be used.

An additional factor discussed in the CONRAIL Final System Plan for restructuring railroads in the Northeast [99] may result in increased unit train rates unrelated to the cost of service. In this plan the United States Railway Association (USRA) observes that transportation costs have decreased as a percentage of delivered coal prices from 41.3 per cent in 1965 to 20.8 per cent in 1974, on a national basis. Also, since the demand for coal is increasing, the price of competitive fuels is increasing, and the regulatory atmosphere appears to be receptive, the USRA concludes that 50 cents per ton increase in coal rates would generate $34 million in revenue for CONRAIL without significantly damaging coal's competitive situation or decreasing the railroad coal traffic [100].

The 1978 estimate of unit train rates from Westmoreland County to Salem is obtained by escalating the 1976 rate and adding an approximate $0.50 per ton surcharge as suggested by the USRA. Thus, the estimated transportation cost of coal is $12.00 per ton, or 48 cents per MBtu, in 1978.

4.2.3 Total Delivered Coal Costs

The estimates of the 1978 total cost of coal delivered to the proposed plant in Salem as a function of sulfur content are presented in Table 4.4.

TABLE 4.4

DELIVERED COST OF COAL TO SALEM, MASSACHUSETTS (1978 $)

	LOW SULFUR COAL (0.7%)	MEDIUM SULFUR COAL (1.5%)	HIGH SULFUR COAL (3.5%)
F.O.B. PRICE AT MINE ($/ton)	51.50	29.75	22.30
TRANSPORTATION COST ($/ton)	12.00	12.00	12.00
DELIVERED COST			
$/ton	63.50	41.75	34.30
¢/MBtu	254	167	137

4.3 Non-Fuel Operating and Maintenance Costs for Coal-Fired Power Plants

Non-fuel operating and maintenance costs can be separated into the following accounts:

> Staff expenses, including the hourly earnings payroll, fringe benefits, and supervisory labor expenses.
>
> Maintenance materials are those materials required to repair or replace equipment during scheduled and forced outages by plant maintenance personnel.
>
> Supplies and expenses such as consumable materials and expenses that are unrecoverable after usage. These include makeup fluids, chemicals, gases, lubricants, office supplies, and offsite contract services.
>
> Administrative and general expenses are offsite administrative expenses allocated to the plant such as management and professional personnel who are not part of the operating staff.

Operating and maintenance costs are classified as fixed if they are independent of plant output, and variable if they are dependent on plant output.

Oak Ridge National Laboratory (ORNL) has prepared a computer code entitled OMCOST to estimate operating and maintenance costs for large steam electric power plants [101]. The code was prepared by developing cost functions versus plant size for the accounts listed above based on the operating experience of large nuclear, coal, oil and gas-fired power plants. Costs are calculated for the specific power plant type and size, year of operation, type of cooling system, load factor, and thermal efficiency. In addition to these plant parameters, the following input variables were specified for this analysis:

> Cost reference year = 1978
>
> Wage rate before adders (1975 \$) = \$8.00/man-hour

Fringe benefits = 30% of wage rate

Plant supervision expenses = 10% of wage plus fringe benefits

The OMCOST code calculates costs for plant sizes down to 400 MWe. Therefore, costs for the 200 MWe plant were calculated separately by scaling down the costs of the 500 MWe plant. Costs for each of the proposed plants were adjusted by subtracting out the previously calculated estimates of electrostatic precipitator operating and maintenance costs which are included in the OMCOST estimate. Non-pollution control operating and maintenance costs did not vary significantly with and without a FGD installation, so only a single estimate was made for each plant size. The 1978 operating and maintenance cost estimates, exclusive of air pollution control costs, are summarized in Table 4.5.

TABLE 4.5

OPERATING AND MAINTENANCE EXPENSES FOR COAL-FIRED POWER PLANTS
(NOT INCLUDING AIR POLLUTION CONTROL COSTS; 1978 $)

	1000 MWe	500 MWe	200 MWe
FIXED COSTS	9,204,000	7,497,000	5,000,000
VARIABLE COSTS	412,000	233,000	110,000
TOTAL COSTS			
dollars	9,616,000	7,730,000	5,110,000
mills/Kwh	1.46	3.53	14.6

4.4 Total Economic Costs of Coal-Fired Electric Power Generation

The busbar cost of electricity in any given year can be estimated from the following formula:

$$e = \frac{1000}{8766 \cdot L}\left[\Phi\left(\frac{I}{K}\right) + \left(\frac{O}{K}\right)\right] + (f \cdot h)10^{-5} \qquad \text{[Eq. 4.1]}$$

where:

e = busbar cost of electricity, mills per kilowatt-hour;

L = plant load factor;

Φ = annual fixed charge rate;

$\frac{I}{K}$ = initial capital investment, dollars per kilowatt;

$\frac{O}{K}$ = non-fuel operating and maintenance costs, dollars per kilowatt;

f = unit fuel costs, cents per MBtu;

h = plant heat rate, Btu/Kwh

In this analysis, the busbar cost will be separated into electricity generation and air pollution control costs. The estimated cost components of Eq. 4.1 are summarized for each power plant size in Table 4.6. The SO_2 control processes listed are those which satisfy all applicable air pollution regulations, including the significant deterioration increment. The fixed charge rate, Φ, is the constant of proportionality which, when applied to capital investment costs, approximates the total fixed costs incurred per year. The fixed charge rate can be calculated for the ith year (neglecting income taxes) from the expression:

$$\Phi_i = \pi + d_i + r\left(1 - \sum_{j=1}^{i-1} d_j\right) \qquad \text{[Eq. 4.2]}$$

TABLE 4.6

BUSBAR COST COMPONENTS FOR ELECTRICAL GENERATION COMPLYING WITH ALL AIR POLLUTION REGULATIONS (1978 $)

	1000 MWe	500 MWe		200 MWe	
SO_2 CONTROL OPTION	FGD	FGD	LS COAL	FGD	LS COAL
GENERATION COSTS					
Capital, $/KW	411	495	495	671	671
Fuel, ¢/MBtu	137	137	137	137	137
O & M, mills/Kwh	1.56	3.53	3.53	14.6	14.6
AIR POLLUTION CONTROL COSTS*					
Capital, $/KW	85.6	92.1	14.8	110.2	16.2
Fuel, ¢/MBtu	-	-	117	-	117
O & M, mills/Kwh	1.98	2.48	0.23	6.27	0.37

* Note: Air pollution costs include particulate and SO_2 control. The FGD option consists of limestone slurry scrubbing with an ESP. The low sulfur coal option consists of an ESP and the marginal cost of LS versus HS coal.

where:

π = the annual property tax rate;

d_i = the book depreciation charge rate;

$r\left(1 - \sum_{j=1}^{i-1} d_j\right)$ = the rate of return of the fraction of the initial undepreciated investment

The value of this fixed charge rate changes each year and thus is not convenient for evaluating fixed costs over the lifetime of the plant. Rather, a constant or levelized fixed charge rate will be used (see Section 3.3.1). The application of the levelized rate results in the same discounted present worth for fixed costs over the plant lifetime as the time-varying rate. The levelized fixed charge rate for a "typical" Massachusetts utility in 1976 was estimated in Section 3.3.1 as $\overline{\phi} = 0.1762$. This estimate was based on current federal and Massachusetts tax and insurance rates, and on a straight-line depreciation of the initial capital investment over a 30-year period. These parameters are not subject to much variation with time. However, the other parameter necessary to arrive at a levelized fixed charge rate, the effective discount rate x, is highly variable. The effective discount rate is the rate the utility must pay for capital including the effect of income taxes. The formula for it is:

$$x = r_b f_b\left(1 - \tau\right) + r_s f_s \qquad \text{[Eq. 4.3]}$$

where:

f_b, f_s = the fraction of utility assets raised from bondholders and stockholders respectively;

r_b = the average interest rate paid to bondholders;

r_s = the average dividend rate paid to preferred and common stockholders;

τ = the income tax rate

The stock fraction for utilities typically varies between 50 and 60 per cent. Both f_b and f_s are assumed to be 50 per cent in this analysis. Utility bond and stock rates in 1968 were on the order of 4.9 and 7.6 per cent respectively, but by 1975, they had increased to approximately 9.5 and 16 per cent. A levelized fixed charge rate calculated using current bond and stock rates would be quite high. However, it is unlikely to be representative of average rates over a 30-year period. In this analysis, the average bond interest rate will be assumed to be 8.0 per cent and the average stock dividend rate 12.0 per cent.

Two types of busbar costs will be estimated. The first is a unit cost of electricity calculated in constant 1978 dollars. Each of the cost components have been referenced to the year 1978 for this purpose. The levelized fixed charge rate is used to estimate capital carrying charges. This busbar cost is meaningful if it were either assumed that costs during the initial years of plant operation are equal to the 1978 costs in real, noninflated, dollars, or if the plant were assumed to be operating in 1978. Busbar costs in 1978 dollars are useful for comparison with actual busbar costs reported by the utilities. Table 4.7 and Figure 4.5 present the estimates of 1978 busbar costs of electricity generation for the SO_2 control options which satisfy all applicable air pollution regulations. For the 1000 MWe plant, only the use of an FGD system will cause air quality in the vicinity of the plant to remain within the significant deterioration increment (see Section 3.4). Either the use of sulfur coal or FGD is satisfactory for the other plants. As shown in Figure 4.5, high and low variants of busbar costs were also calculated. The variants were based on maximum and

TABLE 4.7

BUSBAR COST OF ELECTRICITY FROM NEW COAL-FIRED PLANTS COMPLYING WITH ALL AIR POLLUTION REGULATIONS (1978 $)

	1000 MWe	500 MWe		200 MWe	
SO_2 CONTROL OPTION	FGD	FGD	LS COAL	FGD	LS COAL
LOAD FACTOR, %	70	50	50	20	20
GENERATION COSTS, mills/Kwh					
Capital, ($\overline{\Phi}$ = 0.1762)	11.80	19.90	19.90	67.44	67.44
Fuel	12.24	12.66	12.33	13.08	12.74
O & M	1.56	3.53	3.53	14.60	14.60
Subtotal	25.60	36.09	35.76	95.12	94.78
*****					
AIR POLLUTION CONTROL COSTS, mills/Kwn					
Capital, ($\overline{\Phi}$ = 0.1762)	2.46	3.70	0.60	11.08	1.63
Fuel	-	-	10.53	-	10.88
O & M	1.98	2.48	0.23	6.27	0.37
Subtotal	4.44	6.18	11.36	17.34	12.88
TOTAL	30.04	42.27	47.12	112.47	107.66

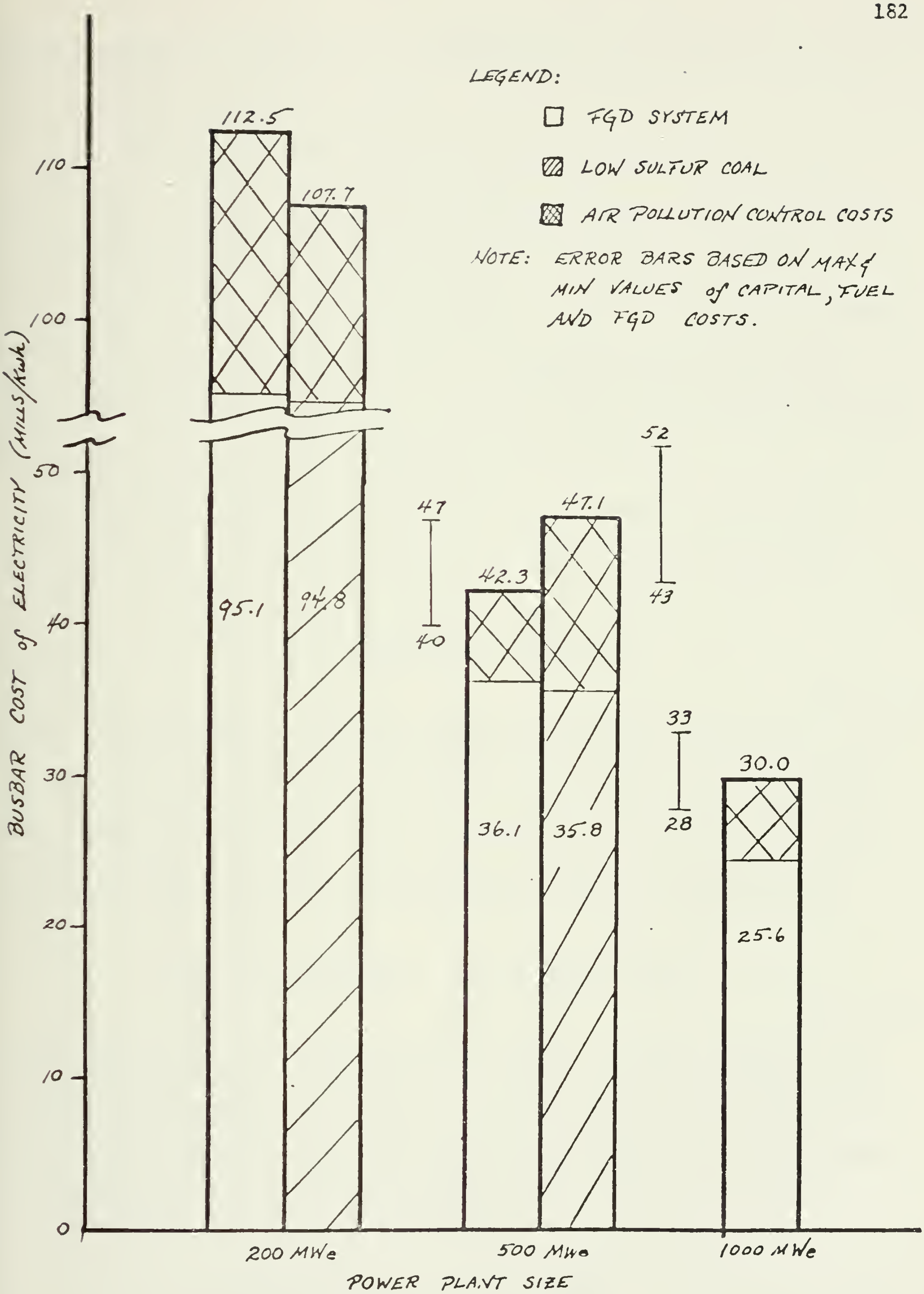

FIGURE 4.5 BEST ESTIMATES of BUSBAR COST of ELECTRICITY FROM NEW COAL-FIRED POWER PLANTS. (1978 $)

minimum estimates of power plant and FGD capital costs, and delivered coal costs as discussed in prior sections.

The second type of busbar cost is a levelized cost. This is the cost, which, if kept constant over a specified period of time, will yield the same discounted present worth of revenue as the actual time-varying cost. Levelized cost estimates use inflated dollars and are not referenced to a specific year, rather the costs are averaged over the levelizing period. These costs are useful for comparing future electricity generation alternatives and are frequently employed in such analyses.

The levelized busbar cost, $\bar{e}$ mills/Kwh, is a constant cost which if incurred over the levelizing period would have a present worth of:

$$P.W. = \sum_{i=1}^{n} \frac{\bar{e}\, E_i}{1000(1 + x)^i} \text{ dollars} \qquad \text{[Eq. 4.4]}$$

where E_i is the number of kilowatt-hours of electricity generated in year i, n is the number of years in the levelizing period, and x is the effective discount rate defined in Eq. 4.3. The present worth of the busbar cost is equal to the sum of the discounted operating, fuel, and capital costs:

$$P.W. = \sum_{i=1}^{n} \frac{O_i}{(1 + x)^i} + \sum_{i=1}^{n} \frac{F_i}{(1 + x)^i} + I_0\bar{\Phi} \qquad \text{[Eq. 4.5]}$$

where O_i and F_i are the operating and fuel costs in year i and I_0 is the initial capital investment. Assuming that the appropriate discount rates for all cost components are equal, and that E_i is constant, the expression for the levelized busbar cost simplifies to:

$$\bar{e} = \frac{1000}{nE}\left(\sum_{i=1}^{n} O_i + \sum_{i=1}^{n} F_i + I_0\bar{\Phi}\right) \qquad \text{[Eq. 4.6]}$$

The operating and fuel costs are measured in inflated dollars so that an escalation rate must be assumed for each. Levelized costs are meaningful only when compared with other levelized costs estimated from the same set of assumptions. The levelized coal-fired costs estimated here will be compared with levelized costs for base-load electricity generation in New England estimated by A.D. Little [102]. That study levelized costs over a 15-year period, 1985 to 2000, and assumed an annual escalation rate after 1980 for delivered coal prices of 3.7 per cent and for operating and maintenance costs of 5.0 per cent. The estimates of levelized coal-fired costs using these assumptions are presented in Table 4.8 and Figure 4.6 For the 1000 MWe plant a range of costs is included in Figure 4.6 based on maximum and minimum estimates of plant and FGD capital costs and delivered fuel prices.

TABLE 4.8

ESTIMATED LEVELIZED BUSBAR COSTS OF COAL-FIRED ELECTRICITY GENERATION: 1985 - 2000

	1000 MWe	500 MWe		200 MWe	
SO_2 CONTROL OPTION	FGD	FGD	LS COAL	FGD	LS COAL
GENERATION COSTS, mills/Kwh					
Capital	15.1	25.3	25.3	84.1	84.1
Fuel*	21.5	22.4	21.5	23.0	22.4
O & M†	3.1	7.0	7.0	29.1	29.1
Subtotal	39.7	54.7	53.8	136.2	135.6
*****					
AIR POLLUTION CONTROL COSTS, mills/Kwh					
Capital	3.2	4.7	0.8	13.8	2.0
Fuel*	-	-	19.9	-	19.9
O & M†	4.0	5.0	0.5	12.5	0.6
Subtotal	7.2	9.7	21.2	26.3	22.5
TOTAL	46.9	64.4	75.0	162.5	158.1

Note: * Assumes fuel costs escalate at 3.7% per year from 1980.
† Assumes O & M costs escalate at 5.0% per year from 1980.

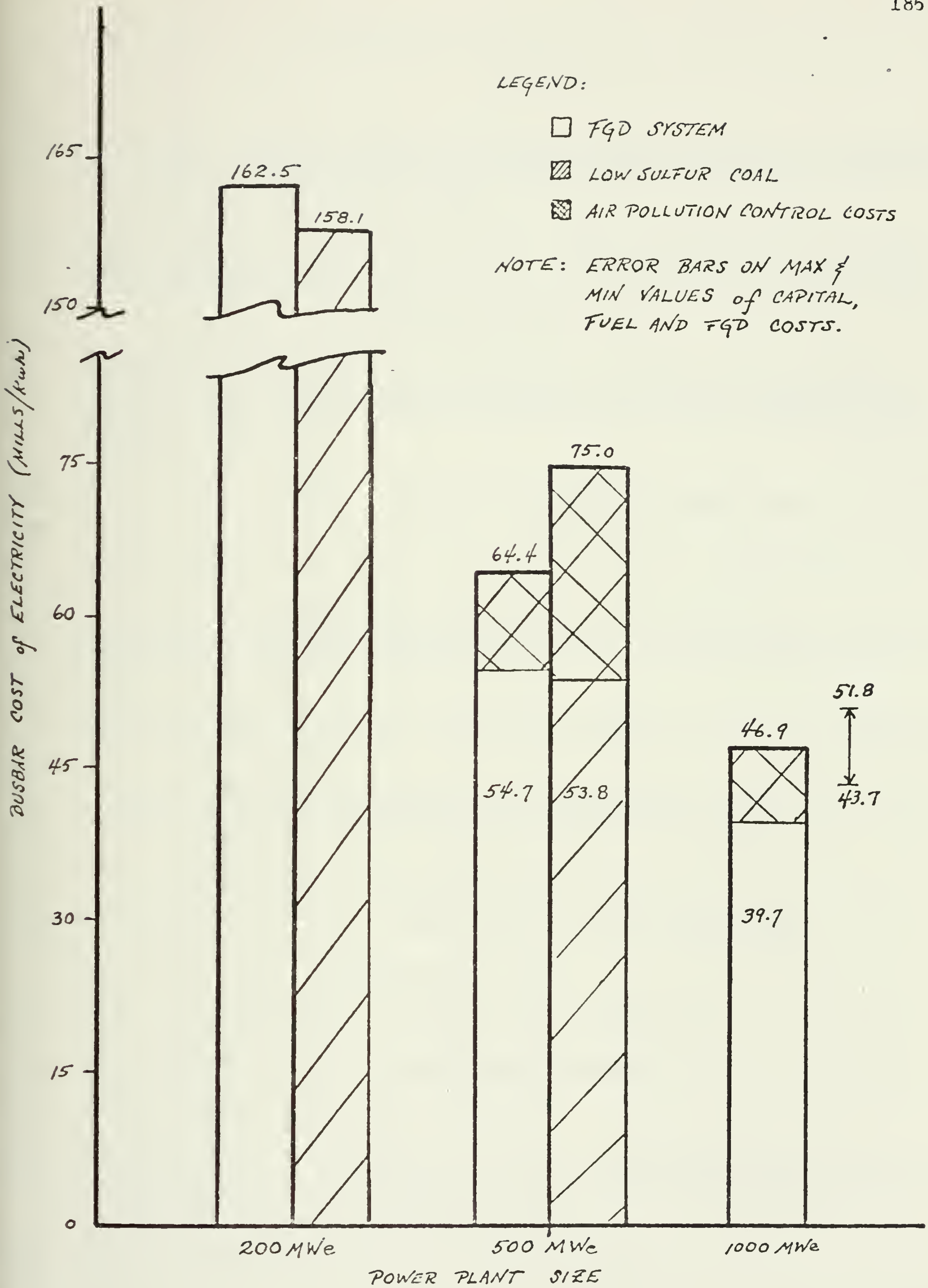

FIGURE 4.6 LEVELIZED BUSBAR ELECTRICITY COSTS FOR NEW COAL-FIRED GENERATION : 1985 – 2000

FOOTNOTES Chapter 4

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CHAPTER 5. PUBLIC POLICY CONSIDERATIONS IN THE UTILIZATION OF COAL

5.1 Near-Term Energy Options for New England: Electricity Generation

5.1.1 Coal versus Oil: Comparative Busbar Costs

In Chapter 2, the criteria by which coal utilization is to be evaluated were defined in terms of regional objectives: to minimize energy costs and environmental impacts, and to maximize the security of energy supply. To assist in the analysis, several critical questions were posed. The first of these questions was:

> Can a coal-fired electric power plant in New England satisfy applicable air quality regulations at an economic cost comparable to projected costs for oil-fired generation?

The analysis of Chapter 3 indicates that all three power plant sizes can meet current, applicable air quality regulations, including the allowable significant deterioration increments. Particulate emissions were assumed to be controlled by an electrostatic precipitator with a collection efficiency of 99.5 per cent. In each case, the use of either low sulfur (0.7%) coal or flue gas desulfurization would satisfy SO_2 emission regulations, but the 1000 MWe plant would require a FGD system capable of 85 to 90 per cent SO_2 removal in order to maintain ground level SO_2 concentrations within the significant deterioration increment. In the two smaller plants, the use of low sulfur coal would not cause the increment to be exceeded. The estimated busbar cost of electricity from coal-fired plants which comply with all air quality regulations can be found in Table 4.7.

Estimates of busbar electricity costs from oil-fired power plants have been made based upon current and projected costs reported by New England Power Planning (NEPLAN) and the New England Electric System (NEES) [103].

NEES reported 1976 busbar costs of operating, maintenance and fuel for oil-fired base and intermediate-load plants. These costs were escalated to 1978 at an assumed 6 per cent annual inflation rate. Capital carrying charges were added by applying the levelized fixed charge rate ($\overline{\Phi}$ = 0.1762) to oil-fired plant capital costs based on 1975 estimates by A.D. Little [104]. The base-load oil-fired plant is assumed to have a capacity of 800 MWe and the intermediate, 500 MWe. The range of capital cost estimates is listed below in 1978 dollars:

Oil-Fired Plant Capital Costs (1978 $)

	Low Variant ($/KW)	Best Estimate ($/KW)	High Variant ($/KW)
800 MWe	370	410	450
500 MWe	430	475	520

Peak-load busbar costs were not available for oil-fired plants since most peak-load fossil plants are either gas turbine or diesel. Therefore, peak-load coal-fired costs were compared to busbar costs estimated by NEPLAN for a gas turbine plant in 1980 dollars. NEPLAN also reported 1980 busbar costs for base and intermediate-load plants. When adjusted to 1978 dollars and a fixed charge rate of $\overline{\Phi}$ = 0.1762, the costs agreed closely with those calculated from NEES data.

Estimated busbar costs of electricity from oil-fired plants in 1978 are presented in Table 5.1. Comparative costs of coal and oil-fired generation in 1978 are displayed in Figure 5.1 divided into capital, operating and maintenance, fuel, and pollution control components. An oil-fired plant burning low sulfur (~ 1%) residual oil can comply with all air quality regulations without using pollution control equipment, and thus air pollution

TABLE 5.1

BUSBAR COST OF ELECTRICITY FROM OIL-FIRED AND GAS TURBINE PLANTS (1978 $)

	BASE LOAD	INTERMEDIATE LOAD	PEAK LOAD
Plant Type	Oil	Oil	Gas turbine
Plant Size (MWe)	800	500	100
Capacity Factor (%)	75	50	10
Generation Costs, mills/Kwh			
Capital	11.0	19.1	-
Fuel	19.8	22.6	-
O & M	1.0	3.2	-
TOTAL, mills/Kwh	31.8	44.9	78.9
TOTAL, COAL-FIRED, mills/Kwh	30.9	42.3	107.7

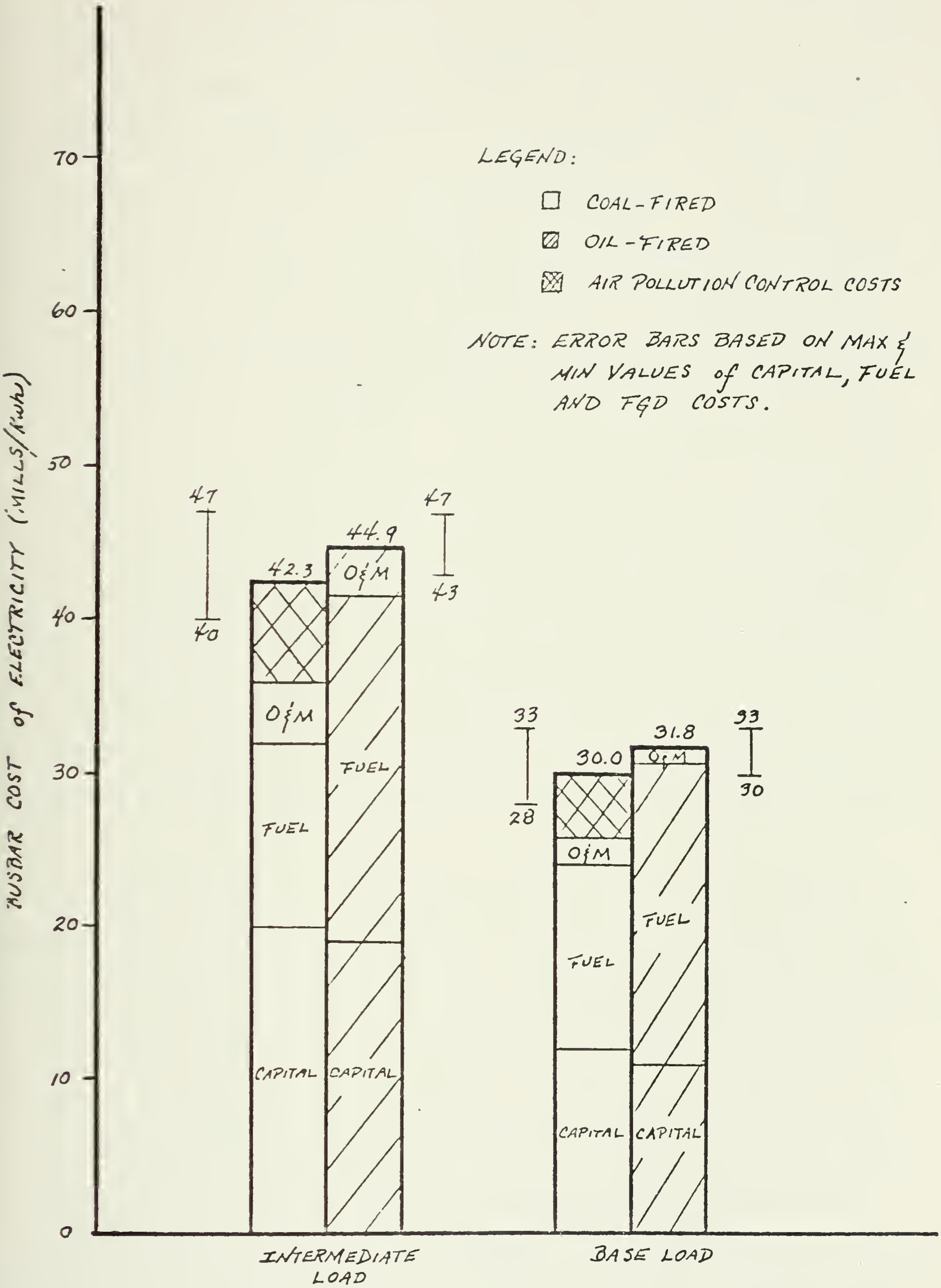


FIGURE 5.1 COMPARATIVE BUSBAR COSTS of COAL AND OIL FIRED ELECTRICITY GENERATION. (1978 $)

control costs were not considered separately.

The best estimates of coal and oil-fired costs indicate coal-fired busbar costs to be approximately 6 per cent lower than oil-fired costs, in 1978 dollars, for both base and intermediate-load plants. Given the uncertainty in the estimates, it is reasonable to conclude that coal and oil-fired costs are at least comparable. Even assuming the highest estimates of capital, FGD, and coal costs does not substantially alter this conclusion. The competitiveness of coal with oil can be accounted for by the delivered price of low sulfur oil to Boston. In 1976, it was approximately 190 cents per MBtu [105] compared with an estimated delivered price of high sulfur coal of 130 cents per MBtu. This is equivalent to a busbar cost differential of 5.4 mills per kilowatt hour which is higher than the estimated annualized cost for a FGD system installed on a base-load 1000 MWe coal-fired plant. The use of a 200 MWe coal-fired plant for peak-load operation is obviously very expensive compared to a gas turbine, for instance, largely because of high capital carrying charges on a plant which has a load factor of 20 per cent.

The levelized busbar costs listed in Table 4.8 can be compared with similar estimates made by A.D. Little [106] for base-load electrical generation. Over the period from 1985 to 2000, A.D. Little estimated the levelized cost of oil-fired generation to be 51.9 mills per kilowatt hour. This is about 10 per cent higher than the estimate of 46.9 mills per kilowatt hour for coal-fired generation calculated in Chapter 4 [107]. Thus, this analysis indicates that a new coal-fired base or intermediate-load electric power plant in New England is capable of conforming to all applicable air quality regulations at a busbar cost that is at least comparable to, and probably slightly less than the cost of oil-fired generation. It is not practical to use a coal-fired plant for peak-loads.

Based on this analysis, the pending federal legislation to require coal in place of oil utilization would not be economically disadvantageous for the New England region, or in conflict with regional objectives and interests. There would appear to be no justification for regional policymakers to oppose such legislation. There is justification for pursuing policies to facilitate the expansion of coal utilization in New England strictly from an economic perspective.

5.1.2 Coal and Other Near-Term Energy Options

At the outset of this thesis, it was stated that coal was to be compared with imported residual oil for electricity generation. As a glance at Figure 5.2 will show, this is one set of alternatives amongst many energy options. As previously discussed, however, the near-term energy options for large-scale electricity generation in New England are realistically limited to coal, oil, and nuclear. For intermediate-load applications, the analysis presented here will be useful to policymakers regardless of the status of nuclear power. Because of its high capital carrying charges, approximately 75 per cent of the busbar cost, nuclear generation is not likely to be widely used for cycling operation with load factors from 40 to 50 per cent. Thus, coal would appear to be the preferred option for intermediate-loads.

For base-load applications, nuclear power would be the least economic cost alternative over the near and long-terms. The levelized busbar cost estimated for coal-fired generation from 1985 to 2000 is nearly 30 per cent higher than the estimate of nuclear busbar costs calculated by A.D. Little [108] using similar assumptions. Coal costs were estimated in this study to be 46.9 mills per kilowatt-hour compared to A.D. Little's estimate of nuclear

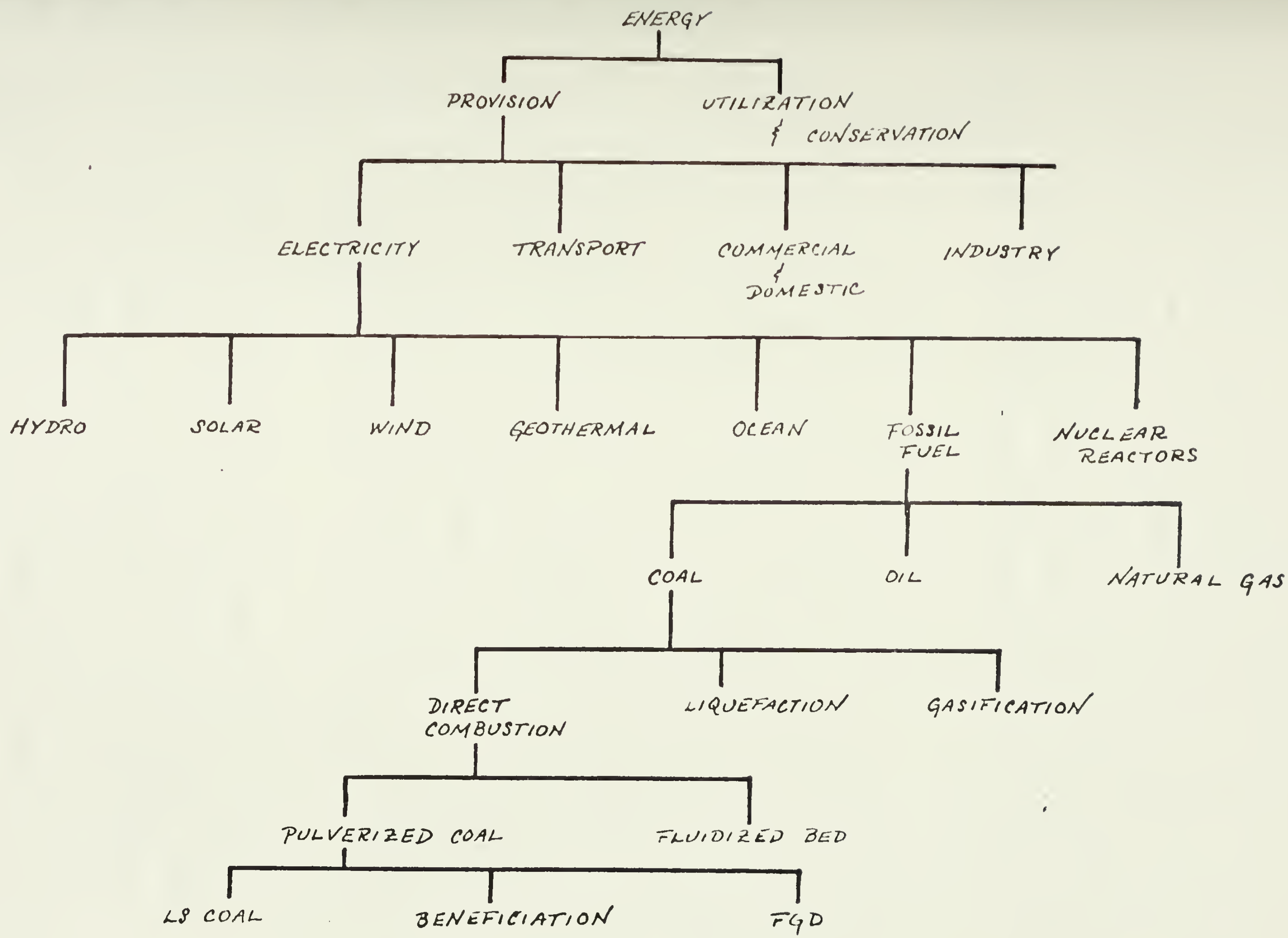


FIGURE 5.2 ENERGY OPTION TREE

at 36.2 mills per kilowatt-hour. To overcome this difference, nuclear capital costs would have to be on the order of 500 dollars per kilowatt higher than coal capital costs at 14 per cent interest [109]. A.D. Little estimates a maximum capital cost differential in 1985 dollars of only 190 dollars per kilowatt. The coal versus nuclear busbar cost difference would not be affected by any realistic uranium price increases. Based on these costs, coal would not be the preferred base-load alternative for New England.

However, in recent years the long-term prospects for nuclear power have been complicated by political uncertainties. Power plant construction permits and licensing have been delayed through legal and administrative procedures by persons opposed to nuclear development resulting in increased interest charges and escalation. Numerous public referenda were held in 1976 on limiting new construction of nuclear power plants [110]. Though all referenda were defeated decisively, the possibility that nuclear construction will be halted by such measures in the future causes uncertainty. Issues concerned with plutonium reprocessing, nuclear proliferation, and development of breeder reactor technology potentially threaten the viability of a long-term nuclear power program. In short, the future of nuclear power is uncertain.

The ultimate resolution of the nuclear issue will come from its acceptance or rejection by the public, not by any decisions a policymaker (particularly a state policymaker) might make. Nonetheless, a state policymaker is in a position to preserve future energy options, or to preclude the elimination of future options. For example, the New England transportation system is currently inadequate to handle a large-scale conversion of power plants to coal (see Section 5.3). Unless some action is taken to upgrade the railroads

in the region, the future option of a coal-based electric power system is severely limited. If nuclear power ceased to be an option, imported residual oil would be the only remaining option for base-load generation.

In summary, then, nuclear power is the preferred option for future base-load electricity generation in New England. The importance of this study with respect to base-load generation is twofold: first, the conclusion that coal is preferable to oil, and second, to highlight the areas which require action to preserve the coal option for the future.

5.2 Environmental Policy Issues

5.2.1 The Adequacy of Air Quality Standards in Protecting Public Health

In making decisions which may affect the public health, the public policymaker has an obligation to be overly cautious, perhaps, in favor of the public health. The long time horizon advocated in Chapter 2 for policymaking implies the anticipation of future effects of current policies. It is much easier and less costly to society to prevent the occurance of deleterious health effedts rather than to try to correct them, and their cause, after they occur. Thus, the determination that coal combustion can meet all applicable ambient air quality standards is not necessarily a sufficient justification for the policymaker to permit coal utilization. The adequacy of the standards in protecting the public health must be evaluated.

The primary ambient air quality standards were supposed to be established at a level sufficient to protect the public health with a margin of safety [111]. The data necessary to establish such levels are inadequate, however. For instance, the threshold levels of pollutants necessary to cause health effects have not been determined; the specific health effects of individual pollutants are not known; the mechanisms by which health effects occur are unknown; and the synergistic effects of two or more pollutants on health are not understood [112]. Furthermore, the data from epidemiological studies is difficult to interpret because levels of several air pollutants are frequently elevated simultaneously. The assignment of observed health effects to a specific pollutant under such conditions is subject to considerable uncertainty.

Despite the tenuous data, Congress required that ambient standards be

established. The evidence suggests that, given the available data, the standards may not have been established at levels sufficiently low enough to protect public health. For example, even though the Air Quality Criteria document for sulfur oxides reported adverse health effects when 24-hour average levels of SO_2 exceeded 300 $\mu g/m^3$, the primary 24-hour standard was set at 365 $\mu g/m^3$. More recently, other studies have found adverse health effects at ambient levels of particulates and SO_2 well below the ambient standards. The EPA [113] reported aggravation of asthma at a 24-hour average SO_2 concentration from 180 to 250 $\mu g/m^3$ and aggravation of cardio-pulmonary symptoms and asthma at 24-hour particulate concentrations from 70 to 100 $\mu g/m^3$. These effects were attributed to suspended sulfate levels with which the effects had the best correlation. However, particulates and SO_2 are sulfate precursors and must be considered at least indirectly responsible for some of the adverse health effects. The EPA's best judgment estimates of thresholds for adverse effects of short-term exposures are 180 $\mu g/m^3$ for SO_2 and 70 $\mu g/m^3$ for particulates. In short, simply insuring that ambient air quality standards are not violated is not tantamount to preventing adverse public health effects.

It has been previously determined that the addition of the proposed power plant would not, by itself, cause any ambient standard violations. Existing background levels of particulates at Salem and Kenmore Square and of SO_2 at Kenmore Square are currently in excess of the "best estimate" threshold for adverse health effects and would be increased slightly by power plant emissions from Salem. However, the ambient SO_2 levels at Salem would be increased approximately 70 per cent to about 160 $\mu g/m^3$ and would approach the "best estimate" threshold. Therefore, it is a legitimate policy issue to consider the degree to which the public health will be

affected by the proposed plants.

In terms of the present analysis, this is a more fundamental issue than the issue of coal-fired compared with oil-fired combustion. The proposed plants are assumed to have the best available pollution control technologies installed, namely precipitators and scrubbers, and it would not be feasible at present to further reduce particulate and SO_2 emissions. In addition, as will be discussed shortly, the emissions from a comparably sized oil-fired plant would be of the same order of magnitude as from the coal-fired plant. The more fundamental issue is whether protection of the public health would permit the addition of any fossil-fuel-fired power plant. That issue will not be addressed here.

5.2.2 Evaluation of the Optimal Degree of Sulfur Oxide Emission Control

Air pollution control costs, primarily SO_2 control costs, comprise approximately 15 per cent of the estimated busbar cost of electricity for the base and intermediate-load coal-fired plants. The cost of control is a function of the degree of emission reduction. One of the stated energy objectives is to minimize the cost of energy, and potential economic savings are available if SO_2 emissions were permitted at levels above current emission limitations, as can be seen in Figures 3.21 through 3.26. Another objective is to minimize environmental impacts due to the plant, and these obviously increase with SO_2 emissions. Thus, a tradeoff exists between economic and environmental costs. The existence of air quality standards and regulations eliminates the necessity for the policymaker to make this tradeoff in each instance, but in this analysis it is of interest to determine whether there may be any justification for changing the existing emission limitations.

The optimal degree of SO_2 control is that which results in the lowest net cost to society -- the net societal cost being the sum of SO_2 control costs and the costs of damage from the SO_2 emissions. Tradeoff curves relating SO_2 emission levels to SO_2 control costs were developed in Chapter 3. The societal costs of SO_2 emissions are due to its adverse effects on human health, vegetation, materials, and property values. If it were possible to assign a dollar value to the marginal or incremental cost of air pollution damage caused by an additional pound of SO_2 emitted to the atmosphere, one could directly determine the net societal cost of a given level of SO_2 emissions. Unfortunately, the estimation of damages due to SO_2 is extremely difficult both in terms of identifying all of the costs associated with air pollution and in assigning a portion of these costs to SO_2 in the atmosphere. Not surprisingly, the exact damage cost of SO_2 emissions is not presently known. However, several attempts have been made to estimate a range of damage costs, including a study conducted by the National Academy of Science (and others) for the U.S. Senate [114]. This study suggests that the total damage cost of SO_2 emissions ranges from 7 cents per pound of SO_2 emitted from a rural power plant to $1.00 per pound from an urban plant. The most probable cost was estimated to be 9 cents per pound for a rural plant and 23 cents per pound for an urban plant.

It is acknowledged that any estimates of SO_2 damage costs are very preliminary and highly uncertain. They are generally obtained by estimating total annual air pollution damage costs in the U.S., assigning a portion of these costs to the various pollutants, and estimating the annual U.S. emissions of each pollutant. Each of these steps is subject to considerable uncertainty. The uncertainty is enhanced by the fact that each pound of a pollutant emitted does not have the same degree of environmental impact at

ground level. For instance, pollutant emissions from tall power plant stacks would result in less ground level exposure per pound of pollutant emitted than emissions from a ground level source such as home heating units. Though coal combustion for electric power generation accounts for over 60 per cent of total U.S. sulfur oxide emissions, it has been estimated that it contributes only 10 to 15 per cent of total ground level SO_2 exposures [115]. Nonetheless, though the estimates of SO_2 damage costs are tenuous, the policymaker can only make evaluations using the best information available and then consider the results cautiously.

Using the estimate of environmental damage at 23 cents per pound of SO_2 emitted, the net societal costs of SO_2 control are displayed in Figures 5.3 and 5.4 for a 1000 MWe and 500 MWe plant. If FGD is considered the best available control technology and its economic cost curve is used, the apparent optimal level of SO_2 control for the 1000 MWe plant occurs well below the New Source Performance Standard Emissions limitation, at least at the 90 per cent SO_2 removal level, since the net societal cost curve has no minimum value. The reason is that the assumed damage costs of SO_2 increase more rapidly, per pound of SO_2 emitted, than the SO_2 control costs decrease. In the case of the 500 MWe plant using FGD for SO_2 control, the estimated optimal control level occurs at approximately the New Source Performance Standard emission level. Eighty per cent removal of SO_2 might be justified in this instance. Regardless, if FGD is a viable control option and if 23 cents per pound emitted is a reasonable approximation of the SO_2 damage function, there would not appear to be a justification for relaxing the SO_2 emission standards; the minimum net societal cost of SO_2 control would occur at an emission level which is within current regulations. Of course, if the marginal damage cost of SO_2 emissions is higher than

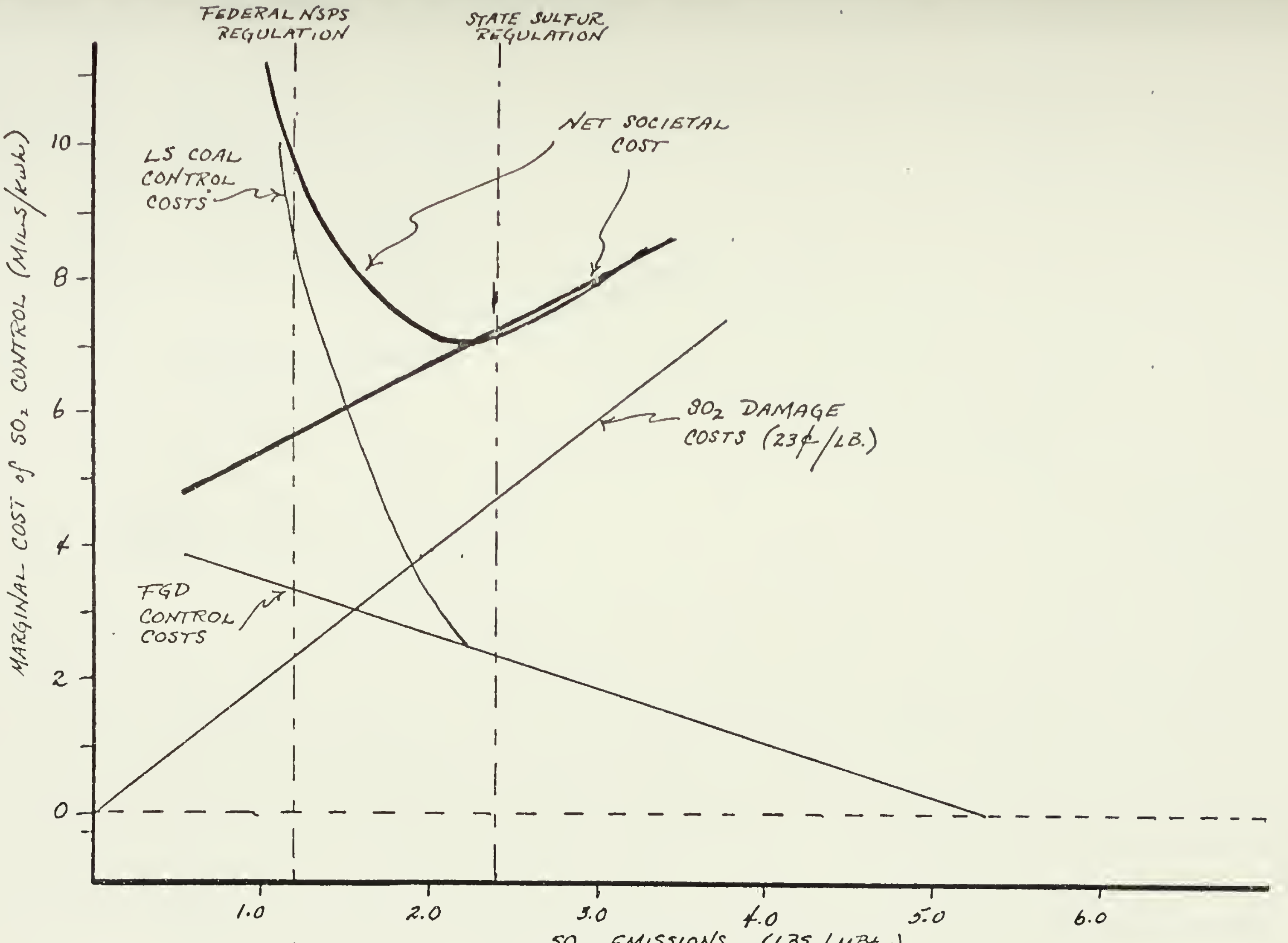


FIGURE 5.3 NET SOCIETAL COSTS of SO_2 EMISSIONS FOR 1000 MWe COAL-FIRED PLANT (1978 $)

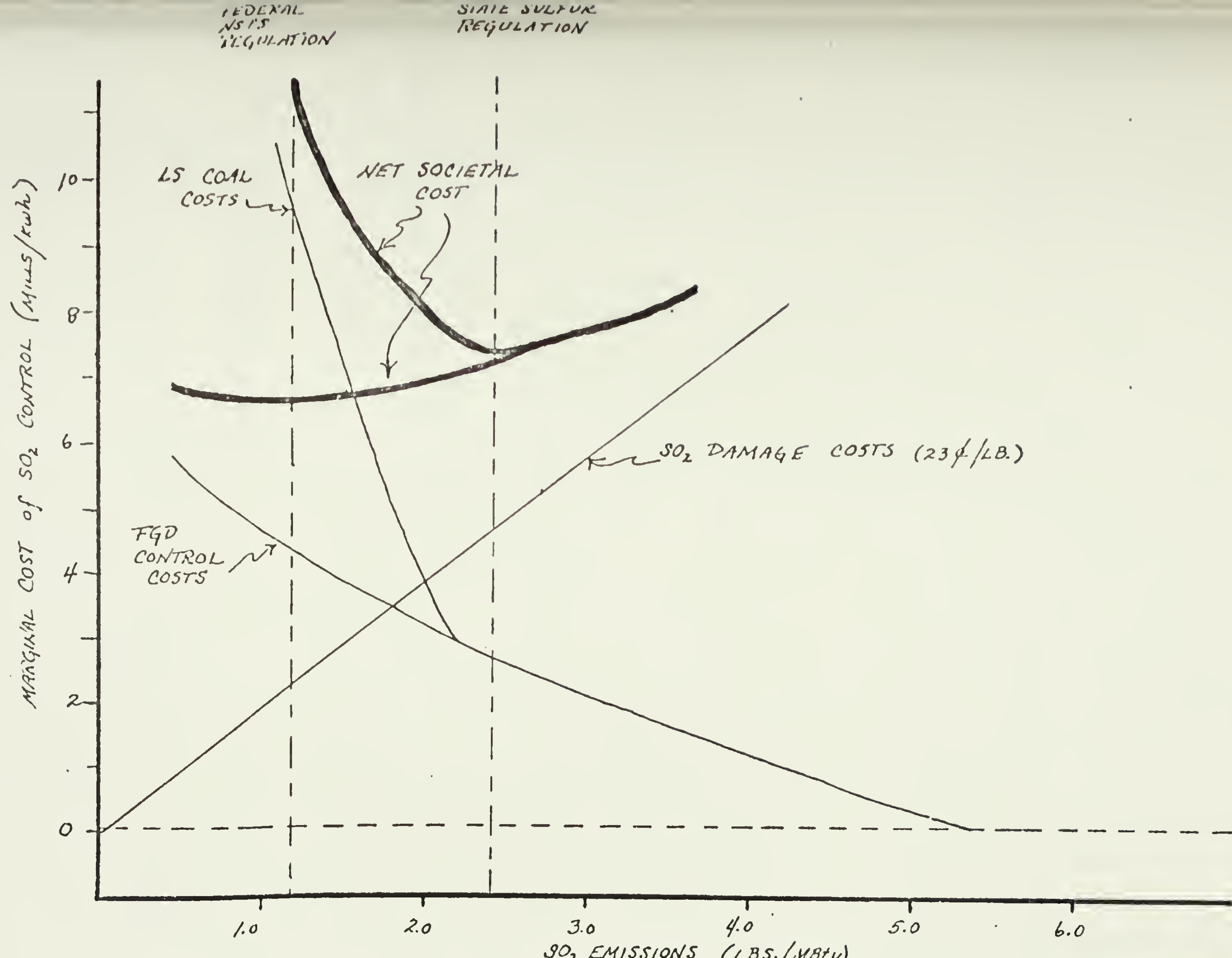


FIGURE 5.4 NET SOCIETAL COST of SO_2 EMISSIONS FOR 500 MWe COAL-FIRED PLANT (1978 $)

23 cents per pound, the minimum net societal cost would occur at an even lower SO_2 emission level. If the damage cost is less than 23 cents per pound, the optimal level of SO_2 removal would be somewhat higher. However, for the 1000 MWe plant, the damage cost would have to be less than 9 cents per pound before the optimum emission level is higher than the current NSPS standard (8.95 cents per pound is equal to the negative value of the slope of the control cost curve). This is very close to the minimum damage costs estimated by NAS for a rural power plant. In terms of the few data available on SO_2 damage costs, flue gas desulfurization appears to be the option which results in the optimal tradeoff between economic and environmental costs by minimizing net societal costs.

If the FGD option were deemed unavailable, (contrary to the best judgment in this analysis), there would perhaps be some justification for permitting increased SO_2 emissions. Because of the high economic costs associated with the use of low sulfur coal, the minimum net societal cost is estimated to occur at approximately 2.4 pounds of SO_2 emitted per MBtu [Figures 5.3 and 5.4], which also happens to be the equivalent emission level of Massachusetts sulfur regulations. If this were the case, policymakers might be justified in considering changes in the emission limitations. A recommendation to that effect will not be made here.

5.2.3 Acid Sulfate Aerosols

Perhaps more significant than the emission levels of any single pollutant are the synergistic effects of two pollutants, namely fine particulates and sulfur oxides. The SO_2 emitted in the power plant plume is transformed at a rate varying from 1 to 20 per cent per hour, depending

on conditions, to sulfate acids which are transported over long distances via the fine particulates. These secondary pollutants are termed acid-sulfate aerosols. While laboratory experiments exposing animals to SO_2 have not supported epidemiological findings of health effects [116], acid-sulfate aerosols have been shown in both laboratory and epidemiological studies to be a major factor in causing disease [117]. Short term exposures to acid-sulfates are thought to aggravate asthma and preexisting heart and lung disorders, and are likely to have been responsible for perceptible increases in daily mortality during air pollution episodes [118].

Restricting the analysis to a consideration of increased mortality from elevated acid-sulfate aerosols, Figure 5.5 shows the mortality data from chronic respiratory disease prepared by the Environmental Protection Agency [119]. The "best judgment" estimate neglects early London and Oslo data and is an intentionally conservative estimate which predicts less mortality than the mathematical fit. The best judgment estimate predicts a threshold for increased mortality due to acid-sulfates at 25 $\mu g/m^3$. Current acid-sulfate levels in the eastern U.S. are 16 to 19 $\mu g/m^3$. If the estimate of the threshold is accurate, there is small margin of safety in existing sulfate levels.

A correlation equation between 24-hour sulfur oxide levels and 24-hour sulfate levels has been estimated based on data from eight U.S. cities [120]. The relation for 24-hour concentrations expressed in $\mu g/m^3$ is:

$$\Delta\chi_{sulfates} = 0.05\chi_{SO_2}$$

With a maximum 24-hour SO_2 concentration of 65 $\mu g/m^3$ [Table 3.31], the 1000 MWe plant would increase acid-sulfate levels by a maximum of 3.3 $\mu g/m^3$ in the vicinity of the plant, and the 500 MWe plant would increase

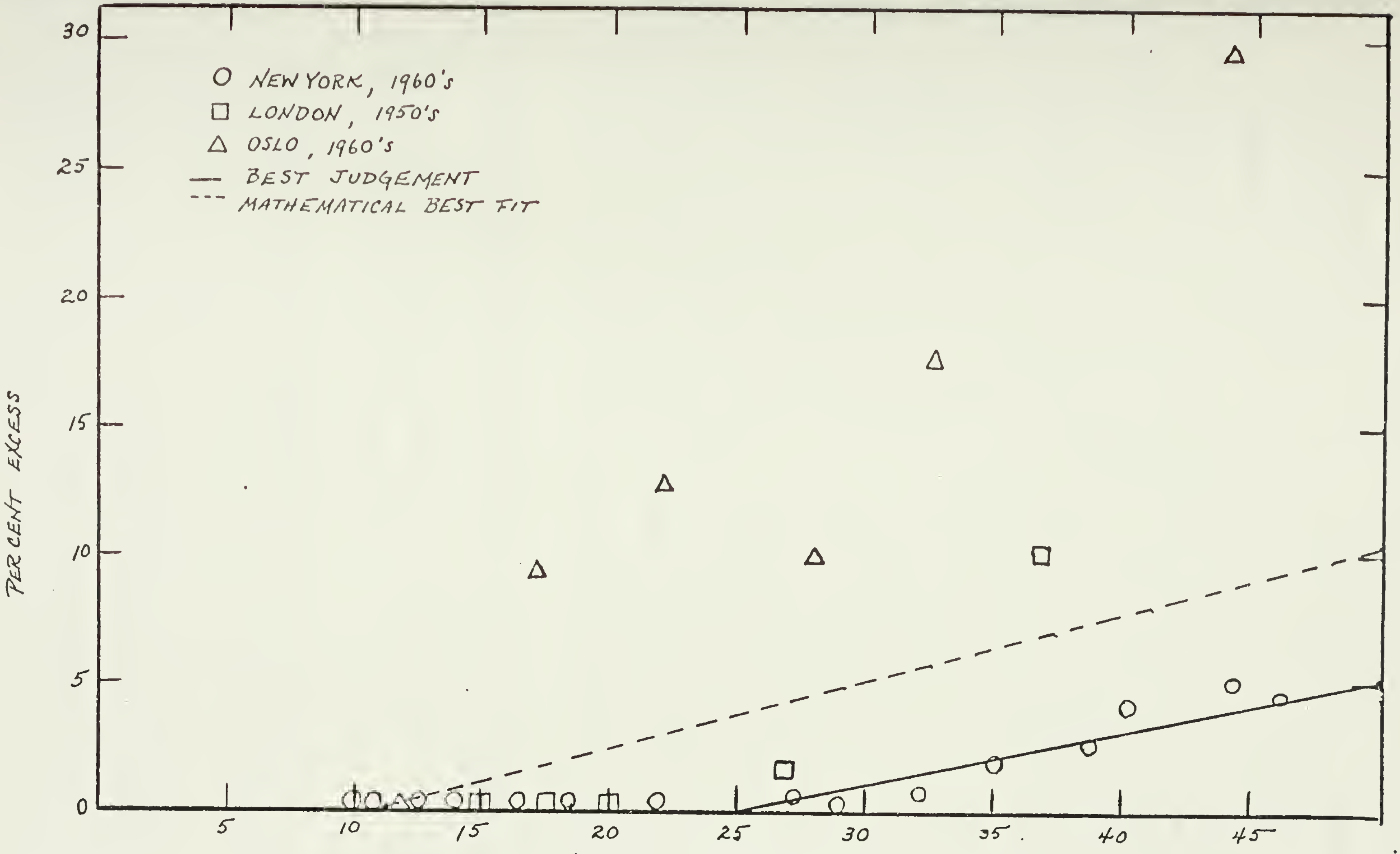


FIGURE 5.5 INCREASED MORTALITY FROM CHRONIC RESPIRATORY DISEASE DUE TO ACID-SULFATE AEROSOLS.

levels about 2.0 $\mu g/m^3$. The elevated sulfate levels would diminish as the plume travels downwind and at the distance from Salem to Kenmore Square, the increase in ambient sulfate levels would be negligible. Again, if the estimated threshold level for excess mortality from sulfates is accurate, emissions from the proposed power plant would not be expected to significantly threaten public health. Using the data shown in Figure 5.5, the EPA has estimated that if the 1975 SO_2 standards were met, the excess mortality in 1980 due to acid-sulfates would be on the order of one death per power plant-year or less [121]. If the mathematical fit of the mortality data is more accurate than the "best estimate", excess mortality could be expected as a result of plant operation. However, the public policymaker has no real basis for disagreeing with the best judgment of experts in this instance. Finally, by controlling particulates and SO_2 emissions to a high degree, the proposed power plants would be employing the only certain methods of reducing sulfate levels outside of building a nuclear instead of a fossil-fired plant or not building the plant at all.

5.2.4 Public Health Effects From Coal-Fired versus Oil-Fired Power Plants

Since this is a comparative analysis of coal versus oil utilization, a second question was postulated in Chapter 2:

> If all air quality regulations can be met, how do coal and oil-fired generation compare in terms of their public health effects?

No information is available on the comparative impacts on health of coal and oil-fired plants both employing the best available control technologies. The alternative, albeit a poor one, is to compare pollutant emission levels. Particulates, sulfur oxides and nitrogen oxides will be considered.

(1) Particulates

Average emissions of oil particulates from power plants are on the order of 1 per cent by weight of uncontrolled coal combustion [122]. However, the use of electrostatic precipitators to reduce coal particulate emissions 99.5 per cent or more by weight approximately equalizes the emissions. The oil-fired plant could use an ESP to further reduce particulate emissions, but would not be required to do so under current regulations. The particles emitted from oil combustion are smaller than from coal combustion, usually less than 1 micron, and thus are potentially more hazardous to human health. The incremental health effects of oil versus coal particulate emissions is indeterminable at present.

(2) Sulfur Oxides

On a unit energy basis, the SO_2 emission limitation for oil is 0.8 pounds per MBtu compared to a coal limitation of 1.2 pounds per MBtu. However, because of the dependence of price of low sulfur oil on sulfur content, low sulfur oil would typically be purchased such that it just satisfies the emission limitations. The use of FGD with 90 per cent SO_2 removal in conjunction with 3.5 per cent sulfur coal would reduce SO_2 emissions to about one-half of the emission limitation, or 0.53 pound per MBtu. Thus, SO_2 emissions from a coal-fired plant could be approximately 30 per cent less on a unit energy basis than the emissions from a comparably sized oil-fired plant.

(3) Nitrogen Oxides

The nitrogen oxide NSPS emission limitation is 0.3 pounds per MBtu for oil-fired plants and 0.7 pounds per MBtu for coal-fired plants. Though NO_x emissions are likely to be higher from coal-fired plants, it is possible to achieve a 40 to 50 per cent reduction in emissions from a coal-fired plant

using low excess air and staged combustion (Section 3.3.3). In this instance, the coal-fired NO_x emissions would be approximately equal to the oil-fired emissions. The differential impact cannot be determined since it has been difficult to establish a correlation between NO_x and human health effects [123].

In short, there is not a consistent difference in pollutant emissions from coal and oil combustion. It is likely that SO_2 emissions from an oil-fired plant would be higher and NO_x emissions lower per unit energy than from an equivalent coal-fired plant. Particulate emission levels probably are comparable unless an ESP were used at the oil-fired plant. Whether the incremental public health costs of higher SO_2 emissions from an oil-fired plant are less than the incremental public health costs of higher NO_x emission from a coal-fired plant cannot be determined. The most that can be concluded is that the emissions from both types of plants are small and that neither plant would cause a violation of any ambient standards. To the extent that adverse health effects occur at ambient pollutant levels below the standards, the marginal difference in the effects between oil and coal-fired plants is likely to be small. As a first approximation, the public health effects from oil and coal-fired generation could be considered approximately equivalent. However, this issue must be highlighted as one which requires more research before it can be resolved.

With respect to emissions, coal does have one important advantage over oil in terms of flexibility. Whereas the SO_2 emissions from an oil-fired plant are close to the emission limitation, the coal-fired emissions, assuming 90 per cent SO_2 removal, are at one-half the limitation. Thus, if at some future time it is necessary to make the emission limitations more stringent, perhaps to control sulfate levels, coal emissions would still be acceptable with a 50 per cent reduction in the emission limitation at no additional cost.

But, in the case of oil, either a change to a lower sulfur, more costly fuel would be required or it would be necessary to install SO_2 removal equipment. In either instance, the cost of oil-fired electricity generation would increase. Therefore, coal utilization under the conditions specified here appears to have more flexibility in coping with changes in SO_2 regulations without incurring additional costs. To a forward-looking policymaker this is an important advantage which is consistent with the policy goals of minimizing future economic and environmental costs.

5.2.5 Environmental Issues Requiring Further Investigation

There have been several items in the environmental analysis which were either subject to considerable uncertainty or not conducive to quantitative analysis. Each item will require further investigation before it can be resolved. They will be highlighted here:

(1) Heavy metals are known to be carcinogenic, but the quantity and impact of power plant emissions on public health are not understood;

(2) Fine particulates emissions cannot be effectively measured or controlled at present, nor is the magnitude of their effect on public health known;

(3) Acid-sulfate aerosols are assumed to have a threshold for causing excess mortality at 25 $\mu g/m^3$, though the actual threshold may be significantly lower. This needs to be determined with more certainty since sulfates have demonstrated a stronger correlation with health effects than any of the other pollutants.

(4) Nitrogen oxide annual average concentrations, which are the basis for the NO_x ambient air quality standard, were not estimated but were assumed to be much less than the standard based on calculated maximum 24-hour averages. This should be verified using modelling techniques. Also, the health effects resulting from elevated levels of NO_x emissions from coal combustion compared with oil combustion were not subject to estimation.

(5) The comparative health impacts resulting from coal and oil combustion were not determined and need to be evaluated.

In an initial analysis such as this, it might be assumed that none of these uncertainties are large enough to alter the conclusion as to the environmental acceptability of coal utilization based on estimable factors like conformance to air quality standards. However, the cautious policymaker must not lose sight of these uncertainties once a conclusion has been made. Rather, he should return to them for further investigation and resolution. Because of his perspective which should transcend disciplinary and professional boundaries, the policymaker should take an active role in defining the issues of public importance. And, the policymaker is in a unique position to focus public, academic and governmental attention on these issues through a number of means including public hearings, conferences called to discuss a particular issue, establishment of commissions or task forces comprised of experts on the issue, the assistance of state and federal agencies and laboratories, and perhaps through funding academic research if money is available.

5.2.6 Summary of Environmental Policy Issues

Coal combustion is capable of meeting all applicable air quality regulations. But, it would elevate SO_2 ambient concentrations at one kilometer from the plant to levels approaching the minimum threshold for observed adverse health effects. This may provide a reason for building a nuclear plant or no plant at all, but it must be noted that particulate levels at the plant, and particulate and SO_2 levels at Kenmore Square already exceed

the minimum threshold for observed effects. So the problem is much larger than the incremental addition of emissions from one plant to the atmosphere. It involves more accurately identifying threshold levels and achieving a general reduction in emission levels. In the case of the proposed plant, the best available control technologies would be applied, but there are numerous other sources contributing to the high pollutant levels where best available control technologies are not applied. Emission reductions from these sources would surely go a long way towards achieving a significant reduction in ambient pollutant concentrations.

The proposed plants would increase acid-sulfate levels a maximum of about 2 to 3 $\mu g/m^3$; from 16 to 19 $\mu g/m^3$, to 18 to 22 $\mu g/m^3$. These levels would still be slightly below the EPA best estimate of sulfate threshold concentrations for causing increased mortality from respiratory diseases. If the threshold is actually much lower than the best estimate, sulfate levels would currently be responsible for causing excess mortality. If that were found to be the case, significant reductions in particulate and SO_2 emissions would certainly be required.

If future reductions in SO_2 emission limitations are possible, coal combustion provides a more flexible alternative than oil combustion. Oil-fired emissions are currently at the emission limitation level, whereas coal-fired emissions are at one-half the limitation. Thus, a 50 per cent reduction in SO_2 emission limitations would not affect the cost of coal combustion but would add significantly to the cost of oil-fired generation.

A final comment concerns the comparative health effects of nuclear versus fossil-fired electricity generation. Not only are the current economic costs of nuclear generation considerably less than fossil-fired generation, the health effects attributable to air pollution during normal plant operation

are also less. Leskovjan [124] reported total annual fatalities due to air pollution from the operation of a 1000 MWe fossil-fired plant as 7.2 and annual morbidity per 1000 MWe plant as 16.1 person-years, compared with total annual fatalities of 0.5 and annual morbidity of 2.1 for a 1000 MWe nuclear plant.

5.3 Economic Policy Issues

Several critical assumptions were made in the economic analysis which require further investigation before reaching a final conclusion on the economics of coal utilization. The first assumption was that flue gas desulfurization will be a mature technology capable of high availability by the time commercial plant operation begins in 1985. It would be useful to obtain current data on the operation of FGD units whose installation was completed during the past two years and to obtain current opinion from utilities, FGD vendors and researchers on the near-term prospects for flue gas desulfurization technology.

The second assumption was that future F.O.B. at the mine coal prices will remain within 10 per cent of the 1975 coal prices in constant dollars. That is, coal prices were assumed to escalate at about the general inflation rate. Any future market perturbations cannot be predicted and were not considered. In addition, since the economic acceptability of coal utilization is largely a function of delivered coal prices, an updating of the coal price data to 1977 would be prudent.

It was also assumed that the unit train transportation of coal would be available from western Pennsylvania to Salem, Massachusetts. The utilization of coal in New England is contingent upon reliable transportation of coal. However, the two railroads which could haul coal to New England are bankrupt. Penn Central has been reorganized into CONRAIL. Boston and Maine, which operates the unit trains which haul coal to Concord, New Hampshire, is also bankrupt but has chosen not to join CONRAIL. The railroad's financial status raises the question whether they will be able to make the requisite equipment acquisitions and track upgrading and maintenance to operate unit trains. Presumably, the Railroad Revitalization and Regulatory Reform Act of 1976

which provided $1.6 billion for "facilities maintenance, rehabilitation, improvements, and acquisition" to the nation's railroads and which authorizes purchase of $4.1 billion in CONRAIL securities, should assist the railroads in meeting these expenses [125]. A study being conducted by the New England Regional Commission has placed the rail rehabilitation needs of the region's rail system at $260 million. Of this, $160 million is needed on CONRAIL right-of-way, and $100 million is needed on other rights-of-way [126]. The specifics of the study are confidential for proprietary reasons so it was not possible to determine how much rehabilitation would be required on track to be used for unit trains. Regardless, the capital required would be significant.

The Final System Plan for restructuring railroads in the Northeast does not inspire confidence that capital would be available from the federal government. There are no routes in New England which receive a Priority I classification for rehabilitation over the next ten years [127]. Priority I lines include those which are to carry freight trains at 60 miles per hour, which happens to be a preferred speed for unit trains. All New England routes are classified Priority II for "those lines not included above" and for which there exists no specific time-frame for rehabilitation. One is left to ponder whether New England railroads could afford to operate unit trains even with the passage of the Railroad Revitalization Act.

In addition to the need for track rehabilitation, unit train coal transportation would require a substantial investment in equipment. The 1000 MWe power plant would use approximately 2.3 million tons of coal annually. This would necessitate 255 deliveries per year from 9,000 ton unit trains. If the trains operated on a five day cycle between Pennsylvania and Salem, four complete unit trains would be required. Each train would consist of four locomotives at $4000,000 per unit and 90 hopper cars at $30,000 per

car in 1975 dollars [12]. The net investment for one 1000 MWe plant would be approximately $17 million in 1975, or $20 million in 1978. This represents about 4 per cent of the total capital investment in the plant.

The investment in track rehabilitation and equipment for a large-scale coal utilization policy would be substantial. For example, for the equivalent of five 1000 MWe power plants, assume the investment in track rehabilitation to be $100 to $200 million, and the total investment in equipment to be $100 million. A total investment of approximately $200 to $300 million would be necessary. This represents about 10 per cent of the capital investment in all five power plants.

The question is where will the capital come from. It is possible that the utilities would purchase the equipment, though the issue of whether such investment could be included in the rate base would have to be resolved. The bankrupt railroads would be unable to provide the necessary capital to upgrade the track and roadbed. The New England states certainly would not have funds of that magnitude available to provide transportation for five power plants. The only remaining source of funds is the federal government. The $200 to $300 million investment represents 13 to 19 per cent of the total funds currently allocated under the Revitalization Act. Since all New England routes are classified Priority II, such funds would not be available and if the were , it would probably represent an inequitable distribution of funds to spend 15 per cent of it on five power plants in New England.

It should be evident that the railroad transportation of coal is likely to be a structural barrier to the large-scale utilization of coal in New England. This is the type of problem the policymaker needs to anticipate. Its resolution will require first, that the federal government be made aware of the problem. Second, it would require the reclassification, or a contingency

plan for reclassification of New England routes necessary for unit train operation to Priority I status for rehabilitation. The involvement and cooperation of the Federal Energy Administration, or its equivalent, and the Department of Transportation would be essential to this effort. Unless policymakers in the various New England states begin to address this problem in the near future, the lack of adequate transportation facilities could seriously hamper any future large-scale coal utilization effort.

FOOTNOTES Chapter 5

103. Telephone conversations with Mr. Art Barstow, New England Power Planning, West Springfield, Massachusetts, 14 January, 1977, and Mr. Frank Brown, New England Electric System, Westborough, Massachusetts, 18 January, 1977.

104. A.D. Little, Inc., <u>Base Load Generation</u>.

105. Center for Energy Policy, Inc., <u>The Impact of Power Plant Coal Conversion</u>, p. 323.

106. A.D. Little, Inc., <u>Base Load Generation</u>, p. 89.

107. The ADL study also estimated coal-fired generation with FGD levelized costs to be 56.8 mills per kilowatt. The difference between this estimate can be accounted for. The ADL levelized capital cost value of 23.7 mills/kwh is incorrect. Using the ADL fixed charge rate of 0.194, the most probable value for capital cost of 697 dollars per kilowatt, and a load factor of 70%, the capital cost equals 22.0 mills per kilowatt hour. If $\bar{r}$ = 0.1762 is used, the capital cost becomes 20.0 mills/kwh, and the total cost would be 53.1 mills/kwh. Finally, ADL assumes a mine mouth coal price of $30 per ton in 1974-1975 for high sulfur coal instead of $18.75 per ton.

108. A.D. Little, Inc., <u>Base Load Generation</u>.

109. David J. Rose, <u>et al.</u>, "Nuclear Power -- Compared to What?", <u>American Scientist</u> Vol. 64 (May - June, 1976), p. 297.

110. Nuclear power referenda were held in Arizona, California, Colorado, Montana, Oregon, Washington, and Ohio in November, 1976.

111. Clean Air Act Amendment of 1970, Section (b)(1).

112. Larry L. Leskovjan , "An Estimate of Public Health Costs of Air Pollution From Fossil-Fueled Power Plants," (Environmental Engineer thesis, Massachusetts Institute of Technology, April, 1974), p. 105.

113. U.S. Environmental Protection Agency, <u>Health Consequences of Sulfur Oxides: A Report From CHESS, 1970-1971</u> (Research Triangle Park, N.C., U.S. Environmental Protection Agency, 1974), p. 7-22.

114. National Academy of Science, National Academy of Engineering, and National Research Council - Commission on Natural Resources, <u>Air Quality and Stationary Source Emission Control</u>, prepared for the Committee on Public Works, U.S. Senate, Washington, D.C., March, 1975.

115. Larry L. Leskovjan , <u>An Estimate of Public Health Costs</u>, p. 78.

116. Y.C. Alaire, <u>et al.</u>, "Long-Term Continuous Exposures to Sulfur Dioxide in Cynomolgus Monkeys," <u>Arch. Environmental Health</u>, Vol. 24,(1972), pp. 115 - 127.

117. C.R. McJilton, et al., "Role of Relative Humidity in the Synergistic Effect of a Sulfur Dioxide - Aerosol Mixture on the Lung," Science, Vol. 182 (1974), p. 503-504.

118. National Academy of Science, et al., Air Quality and Stationary Source Emission Control.

119. Ibid.

120. Ibid.

121. David J. Rose, et al., "Nuclear Power -- Compared to What?" p. 295.

122. Charles Komanoff, et al., The Price of Power, p. 17.

123. L.D. Hamilton and S.C. Morris, "Health Effects of Fossil-Fired Power Plants, Paper presented to the Health Physics Society Symposium, Knoxville, Tenn, October 22, 1974, p. 3.

124. Larry L. Leskovjan, An Estimate of Public Health Costs, p. 89.

125. Railroad Revitalization and Regulatory Reform Act of 1976, Public Law 94-210.

126. Telephone conversation with David Stein, New England Regional Commission, Boston, Massachusetts, May 7, 1976.

127. Railroad Revitalization Act of 1976.

128. Lawrence T. Forbes, Norfolk and Western Railway Co., Statement before The Committee on Public Works, U.S. Senate, Greater Coal Utilization, July 1, 1975, p. 2043.

CHAPTER 6. CONCLUSIONS

The genesis of this thesis was existing and prospective federal legislation which gives the federal government the authority to order new electric power plants to utilize coal as their primary fuel. It was anticipated that if such a policy were implemented in New England, attainment of regional energy and environmental objectives might be jeopardized by increased electricity costs and elevated air pollution levels. In the initial analysis, in terms of a single large plant, these expectations did not prove to be correct. The conclusions are:

(1) Coal utilization for electric power generation can be both economically desirable and environmentally acceptable in New England compared to oil-fired generation. Compared to nuclear generation for base-load applications, coal is not economically competitive.

(2) At least one structural change would be necessary to implement coal utilization on a large-scale in New England. That change involves substantial improvement in the region's railroad track, probably with federal funds. It would require a reclassification of the priority of New England railroads for rehabilitation under provisions of the Railroad Revitalization Act of 1976.

(3) The lowest cost air pollution control options for the 1000 MWe base-load plant (70 per cent load factor) and the 500 MWe intermediate-load plant (50 per cent load factor) are an electrostatic precipitator for particulate collection and a limestone slurry scrubbing system for SO_2 removal.

(4) The best estimates of busbar cost of electricity for base and intermediate-load plants which satisfy all applicable air quality regulations are, in 1978 dollars:

Base-load coal	30.0 mills/Kwh
Intermediate-load coal	42.3 mills/Kwh

These can be compared to the best estimates of comparable oil-fired generation in 1978 dollars:

Base-load oil	31.8 mills/Kwh
Intermediate-load oil	44.9 mills/Kwh

The best estimates of coal-fired costs are 6 per cent less than oil-fired costs. Given the uncertainty in the estimates, coal-fired costs can reasonably be concluded to be comparable to, or less than, oil-fired costs.

(5) The costs of operating a 200 MWe coal-fired plant as a peak-load plant (20% load factor) are prohibitive.

(6) The major factor affecting coal and oil-fired generation costs is the delivered cost of fuel. Fuel costs comprise 30 to 40 per cent of the coal-fired busbar cost and 50 to 60 per cent of the oil-fired busbar cost. This fuel cost differential causes coal generation to be competitive with oil.

(7) Air pollution control costs, primarily SO_2 control costs, comprise approximately 15 per cent of the 1978 busbar cost of electricity. If the highest utility FGD capital cost estimates are used to calculate annualized FGD costs, the pollution costs would increase to 16 per cent of total busbar costs. In any case, air pollution control costs do not appear to be high enough to eliminate the fuel cost advantage in favor of coal.

(8) All applicable air quality regulations, including the significant deterioration regulations, can be met by the proposed power plants. The maximum 24-hour particulate concentrations would be increased 3 per cent near the plant in Salem. The maximum 24-hour SO_2 concentrations would be increased by over 70 per cent within 1 kilometer of the plant, however, no air quality standards would be violated by the increase. At Kenmore Square, 22.5 kilometers downwind from the plant site, the maximum increase in 24-hour particulate and SO_2 concentrations would be immeasurable.

(9) A relaxation of emission limitations cannot be justified in terms of minimizing costs. The lowest net cost to society (SO_2 control costs plus SO_2 damage costs) based on existing best estimates of SO_2 damage costs occurs at approximately the emission level corresponding to the current New Source Performance Standards.

(10) The human health impacts of coal utilization are not quantifiable with any degree of certainty, but are likely to be small given the stringent emission controls to be used by the plants. Also, the impacts from a coal-fired plant would probably be of the same magnitude as from an equivalent oil-fired plant.

(11) Coal utilization would be more flexible in responding to changes in SO_2 emission limitations than oil combustion. Coal emissions with FGD are one-half of current limitations, whereas oil emissions are equal to the emission limitations.

(12) Finally, the utilization of domestic coal is preferable to the importation of residual oil in order to maximize the security of energy supplies to New England.

Coal utilization for electric power generation in New England would appear to satisfy the region's energy and environmental objectives. It could potentially reduce consumer energy costs to a small degree in the near term and perhaps to a larger degree in the longer term. To wit, the world reserves of oil are being depleted more rapidly than the U.S. coal reserves and thus oil prices might reasonably be expected to rise in the future more rapidly than coal prices. Also, reliance on domestic coal supplies provides insurance against international cartel actions to increase prices. The New England economy has been damaged by high energy prices and though coal utilization may not reduce the energy cost differential vis-a-vis the rest of the nation, it may help to stabilize the region's energy costs. At the same time, coal utilization would not cause an environmental disaster. Regional air quality could be maintained at approximately the levels which would be extant from comparable oil combustion.

This study has provided a framework for further analysis of the coal utilization issue or other similar energy alternatives. By separating the busbar cost into capital, fuel, operating and maintenance, and air pollution control components, and by specifying the procedure and assumptions made in estimating the value of each cost component, it is feasible to modify the analysis when additional data becomes available without necessitating a complete revision. This also applies to modifications required if an assumption made in the analysis is incorrect. The comparison of coal utilization with other energy alternatives is facilitated because the procedures and assumptions have been specified and thus the analysis of two or more alternatives can be normalized to a common basis.

APPENDICES

APPENDIX A

Technically Feasible Processes for Removing SO_2 From Stack Gas

Name of Process	State of Develop-ment	Total MW in Operation or Planned	End Products	Comments
I. Throwaway processes				
A. Dry				
1. Limestone injection	Class 1	160	$CaSO_3$ and $CaSO_4$	Limited to 25 percent removal of SO_2 at best.
2. Nahcolite Injection	Class 3	0	Na_2SO_4	Requires baghouse filter to remove SO_2 and fly ash; soluble end product.
B. Wet (closed-loop operation)				Water-pollution regulations probably will not permit open loop operation.
1. Boiler injection of limestone	Class 1	1,200	$CaSO_3$ and $CaSO_4$	Lower precipitator efficiency; undesirable cocurrent operation of scrubber; scaling in scrubber.
2. Scrubber addition of limestone	Class 1	3,600	$CaSO_3$ and $CaSO_4$	True add-on system; removal efficiency is very dependent on type of limestone.
3. Scrubber addition of lime	Class 1	400	$CaSO_3$ and $CaSO_4$	Improved efficiency at the expense of a greater scaling problem.
4. Alkali-limestone	Class 2	1,500	$CaSO_3$ and $CaSO_4$	No scaling in scrubber; smaller scrubbers and liquor flows; scaling is a problem in the precipitation step.
5. Alkali-lime	Class 1	30	$CaSO_3$ and $CaSO_4$	Expensive utilization of lime.
6. Monsanto CALSOX	Class 3	0	$CaSO_3$ and $CaSO_4$	Water-soluble organic absorbent which is regenerated with lime.
II. Recovery processes				
A. Absorption by liquids				
1. Alkali absorbents				
a. Ammonia scrubbing				
(1) Cominco	Class 1	0	SO_2 and $(NH_4)_2SO_4$	Acidulation with H_2SO_4.
(2) Simon-Carves	Class 1	15	$(NH_4)_2SO_4$ and S	Disproportionation of sulfite and bisulfite in an autoclave.
(3) RHC, Czechoslovakia	Class 1	0	SO_2 and NH_4NO_3	Acidulation with HNO_3.
(4) IPRAN, Romania	Class 1	0	SO_2 and $NH_4H_2PO_4$	Acidulation with H_3PO_4.
(5) Showa Denko, Japan	Class 1	20	$(NH_4)_2SO_4$	Oxidation with air.
(6) NIIOGAZ, USSR	Class 1	305	SO_2 and $(NH_4)_2SO_4$	Regeneration by thermal stripping; 65-mw plant converted to gas.
(7) Kuhlmann - Electricite de	Class 1	25	SO_2 and $(NH_4)_2SO_4$	Regeneration by thermal stripping; shut down because of high steam consumption.
(8) TVA	Class 3	--	SO_2 (converted to S in a Claus plant)	Acidulation with NH_4HSO_4.
(9) Monsanto AMMSOX	Class 3	0	SO_2 (converted to S in a Claus plant)	Incineration of ammonium salts.

Appendix A, cont.

Name of Process	State of Development	Total MW in Operation or Planned	End Products	Comments
b. Sodium compounds				
(1) Wellman-Lord	Class 1	125	SO_2 (converted to S)	Thermal stripping of $NaHSO_3$; requires natural gas for reduction of SO_2.
(2) Johnstone	Class 3	0	SO_2 for H_2SO_4 plant	Precipitation with ZnO followed by thermal regeneration.
(3) Ionics - Stone & Webster	Class 2	70	SO_2 (converted to S)	Acidulation with $NaHSO_4$; large amount of electric power required for electrolytic decomposition of Na_2SO_4.
(4) USBM (citric acid)	Class 2	0	Sulfur	Low pH causes corrosion and reduced scrubbing efficiency; difficulty in washing, citrate out of the sulfur.
c. Potassium compounds				
(1) Wellman-Lord	Class 2	25	SO_2 (converted to S)	Shut down because of high energy requirement for stripping and plugging of the absorber by fly ash.
(2) Consolidation Coal (formate)	Class 2	--	H_2S (converted to S)	May not require stack-gas reheat.
(3) TVA (pyrophosphate)	Class 3		SO_2 (converted to S)	Thermal decomposition; further work is planned.
d. Molten carbonates				
(1) Atomics Intern'l	Class 2	10	H_2S (converted to S)	Gas is scrubbed at 800 F.
e. Organic liquids				
(1) Monsanto NOSOX	Class 3	0	SO_2 (can be converted to S or H_2SO_4)	Steam stripping of SO_2 from water-soluble organic absorbent.
2. Alkaline earth absorbents				
a. Magnesium compounds				
(1) NIIOGAS, USSR	Class 1	--	SO_2 for H_2SO_4 plant	95 percent removal of SO_2 from power plant stack gas.
(2) Grillo, Germany	Class 1	10	SO_2 for H_2SO_4 plant	MnO_2 carried along with MgO regeneration at central installation.
(3) Chemico-Basic (MgO)	Class 1	250	SO_2 for H_2SO_4 plant	Central process plant for regeneration.
b. Calcium compounds				
(1) TVA	Class 3	0	SO_2 for H_2SO_4 plant	Operation could be changed to a throwaway basis on short notice.
3. Other liquids				
a. Water (dilute H_2SO_4)				
(1) Chiyoda, Japan	Class 2	60(a)	$CaSO_4$	Liquid-phase catalytic oxidation followed by reaction with limestone; requires large scrubbers.
4. Metal oxides				
a. MnO_2				
(1) TVA	Class 3	0	SO_2 for H_2SO_4 plant	Bench-scale studies only.
b. ZnO				
(1) TVA	Class 3	0	SO_2 for H_2SO_4 plant	Bench-scale studies only.

Appendix A, cont.

Name of Process	State of Develop-ment	Total MW in Operation or Planned	End Products	Comments
B. Sorption by solids				
1. Sodium compounds				
a. Sodium aluminate				
(1) USBM (alkalized alumina)	Class 2	0	H_2S (converted to S)	Pilot-plant testing has been suspended because of granule attrition and sintering.
2. Metal oxides				
a. MnO_2				
(1) Mitsubishi Heavy Industries, Japan	Class 1	110	$(NH_4)_2SO_4$	Dry sorption-wet regeneration; escape of MnO_2 to atmosphere would be health hazard.
b. CuO				
(1) USBM	Class 3	0	SO_2 for H_2SO_4 plant	Sorption is carried out at 575 to 625 F.
(2) Shell	Class 2	30[a]	SO_2 (converted to S)	Sorption is at 800 F; not tested in coal-burning system.
c. MgO			SO_2 for H_2SO_4 plant	Bench-scale studies only; pilot-plant work is planned.
d. CaO				
(1) Esso	Class 3	0	SO_2 for H_2SO_4 plant	Bench-scale studies only; difficult to regenerate.
C. Adsorption on carbon				
1. Regeneration by heating				
a. Reinluft (Chemiebau, Germany)	Class 2	10	SO_2 (converted to S)	Costly consumption of carbon during regeneration; self-ignition of carbon can occur in sorption section.
b. Bergbau-Forschung, Germany	Class 2	25	SO_2 (converted to S)	Similar to above but problems are less severe.
c. Sumitomo-Kansai, Japan	Class 2	62	SO_2 for H_2SO_4 plant	Loss of adsorbent efficiency over extended cycling.
2. Regeneration by washing				
a. Lurgi (Sulfacid), Germany	Class 2	0	Dilute H_2SO_4	Stack-gas reheat is necessary; large inventory of carbon.
b. Hitachi, Japan	Class 1	205	Dilute H_2SO_4	Gas reheating may not be required.
c. Bergbau-Forschung, Germany	Class 2	0	Dilute H_2SO_4	No gas reheating necessary.
d. Takeuchi, Japan	Class 3	0	$(NH_4)_2SO_4$	It is claimed that the carbon is more effective for adsorbing SO_2 when wetted with $(NH_4)_2SO_2$ by washing with aqueous ammonia.
3. Regeneration by reduction				
a. Westvaco	Class 2	15	Sulfur	Further work is being funded by EPA.
D. Catalytic oxidation				
1. Dry systems				
a. High temperature				
(1) Monsanto Cat-Ox	Class 1	115	80 percent H_2SO_4	Catalytic oxidation at 800 F.
(2) Topsoe-SNPA, France	Class 1	0	94 percent H_2SO_4	Catalytic oxidation at 800 F; for treating Claus plant tail gas.

Appendix A, cont.

Name of Process	State of Develop-ment	Total MW in Operation or Planned	End Products	Comments
(3) Kiyoura - TIT, Japan	Class 2	0	$(NH_4)_2SO_4$	Catalytic oxidation at high temperature followed by ammonia addition.
b. Low temperature				
(1) Tyco chamber process	Class 3	0	80 percent H_2SO_4 and 60 percent HNO_3	Simultaneous removal of SO_2 and NO_x; no stack-gas reheat required.
Catalytic reduction				
1. Reduction with H_2S				
a. Peter Spence and Sons, England	Class 3	0	Sulfur	Pilot-plant tests have indicated catalyst poisoning.
2. Reduction with CO				
a. Chevron Research	Class 3	0	Sulfur	High-temperature reduction over a catalyst after combustion with little or no excess air. Produces highly toxic COS.
3. Reduction with carbon				
a. Penn State University	Class 3	0	Sulfur	High-temperature reduction.

ndustrial oil-fired boilers.

APPENDIX B

Limestone Slurry Scrubbing Process Description

There are three main components of a limestone scrubbing system: the scrubber, reaction tank, and thickener [Figure B.1]. The scrubber's function is to promote the intimate mixing of the SO_2 laden flue gas and the limestone, which is introduced into the scrubber as a water slurry of 5 - 15% solids content by weight.

The reaction tank -- also called a holding, recirculation, or delay tank — is the receptacle for the absorbed and reacted materials discharged from the scrubber, formed from the SO_2, water and limestone reactions. The chemical reactions go to completion in the reaction tank yielding discardable precipitates. Reusable slurry is returned to the scrubber and makeup slurry is added as needed.

The thickener, or clarifier, receives the underflow from the reaction tank which still is roughly 5-15% solids by weight suspended in water. In the thickener, the solids are concentrated by sedimentation and subsequently removed to the disposal site. The clarified water is returned to the scrubber for reuse.

The chemistry of the process first involves the absorption of gaseous SO_2 by the scrubbing liquid (water) in the following reactions:

$$SO_2(g) \rightleftarrows SO_2(aq)$$

$$SO_2(aq) + H_2O \rightleftarrows H_2SO_3 \rightleftarrows HSO_3^- + H^+$$

$$HSO_3^- \rightleftarrows H^+ + SO_3^=$$

The limestone is simultaneously dissolved into the scrubbing liquor as follows:

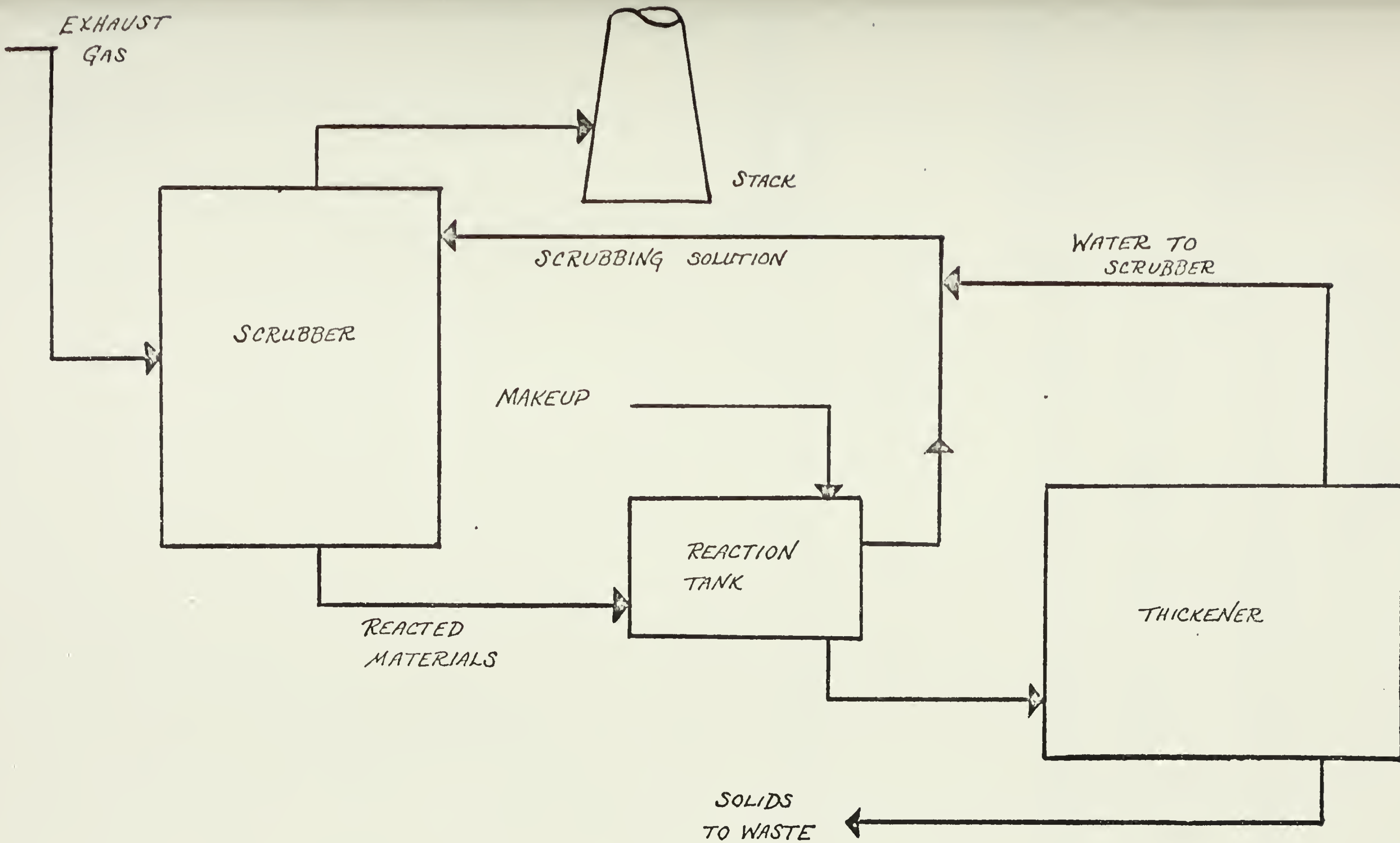


FIGURE B.1 MAJOR COMPONENTS of LIMESTONE SLURRY SCRUBBING SYSTEM

$$CaCO_3(s) \rightleftarrows CaCO_3(aq)$$
$$CaCO_3(aq) \rightleftarrows Ca^{++} + CO_3^{=}$$

Sulfite ions combine with calcium to yield the highly insoluble calcium sulfate hemihydrate.

$$Ca^{++} + SO_3^{=} + 1/2H_2O \rightleftarrows CaSO_3 \cdot 1/2H_2O\downarrow$$

The calcium sulfite may be oxidized to form calcium sulfate (gypsum) through the reaction:

$$SO_3^{=} + 1/2O_2 \rightarrow SO_4^{=}$$
$$Ca^{++} + SO_4^{=} + 2H_2O \rightleftarrows CaSO_4 \cdot 2H_2O\downarrow$$

The calcium sulfites and calcium sulfates precipitate out and are subsequently removed to the disposal site.

APPENDIX C

Wellman-Lord/SO_2 Reduction Scrubbing Process Description

The Wellman/Lord process [Figure C.1] consists of two stages: the removal and concentration of stack gas SO_2, and the reduction of this SO_2 to elemental sulfur. In the first stage, flue gas initially comes in contact with sodium sulfite ($NaSO_3$) in the absorber (1) where the SO_2 reacts to form sodium bisulfite as follows:

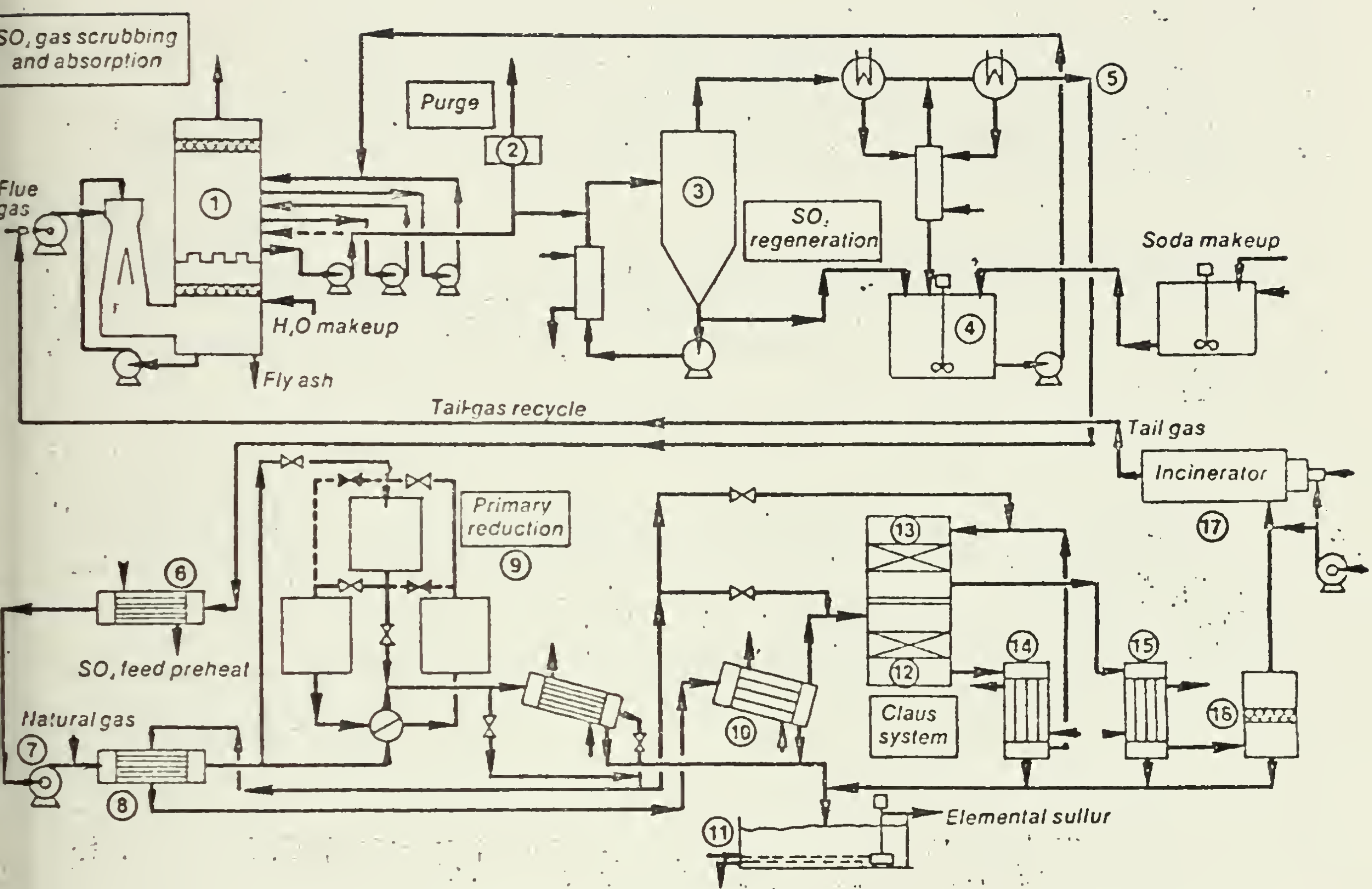
$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

The scrubbed flue gas is discharged to the stack and the sodium bisulfite is discharged to a surge tank (2) and then pumped to an evaporator in the regeneration section (3). Low pressure steam provides heat to the evaporator to drive off SO_2 and water vapor in the reaction:

$$2NaHSO_3 \underset{\text{steam}}{\overset{\Delta}{\rightarrow}} Na_2SO_3\text{(crystals)}\downarrow + SO_2\uparrow + H_2O\uparrow$$

The sodium sulfite precipitates as it forms, and creates a dense slurry of crystals which is dissolved in the dissolving tank (4). The lean sodium sulfite solution is then returned to the absorber via a surge tank. The overhead stream from the evaporator ($SO_2 + H_2O$) is partially condensed to remove most of the water vapor and concentrated SO_2 is discharged from this stage (5).

In the second stage, concentrated SO_2 passes through a preheater (6), is compressed, and natural gas (CH_4) is added in the correct proportions (7). The gaseous mixture passes through a heater (8) where its temperature is raised above the dewpoint of the sulfur formed in the catalytic reduction system (9). The system removes 40% of the elemental sulfur through two



Source: Power, Sept., 1974.

FIGURE C.1. Schematic of Wellman-Lord/SO_2 Reduction Process

reactions:

$$2SO_2 + CH_4 \rightarrow CO_2 + 2H_2O + 2S$$

$$3SO_2 + 3CH_4 \rightarrow 2CO_2 + 2H_2O + 2H_2S + S$$

The removed sulfur is condensed in a cooler (10) and sent to a sulfur holding bin (11).

The gas then passes to a two-stage Claus converter (12, 13) where H_2S and SO_2 react to form water and elemental sulfur:

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S$$

The elemental sulfur is condensed (14, 15) and sent to the holding bin. The residual H_2S in the exit gas is coalesced (16) to remove entrained liquid and then oxidized to SO_2 in an incinerator (17). Tail gas is recycled to the scrubber inlet.

APPENDIX D

Basis of Lime/Limestone Process Design

[Excerpted from PEDCo - Environmental Specialists, Inc. Flue Gas Desulfurization Process Cost Assessment (Washington, D.C.: U.S. Environmental Protection Agency, 1975)]

A. Design Values

The process design basis for the wet limestone system used in this study was determined after review of process designs used or proposed for use at various installations and discussions with control system manufacturers. Figure D.1 presents a typical process flow sheet for the wet limestone process.

The plant evaluated for illustration of design basis is . . .. a single 500 MW, pulverized coal fired boiler with a remaining life of 30 years. The coal burned has a heating value of 12,000 BTU/lb and a 3.5 percent sulfur content. The allowable sulfur dioxide emission rate is the New Source Performance Standard Limitation of 1.2 lb/MM BTU of heat input. The average annual capacity factor is 60 percent. The plant is assumed to be meeting particulate emission rate limitations and thus requires no additional particulate control.

Values of the major overall design parameters are tabulated below:

- Flue gas rate: 1,500,000 ACFM
- Flue gas temperature: 310°F
- Flue gas pressure: atmospheric
- Average inlet SO_2 concentration: 5.54 lb/MM BTU (3.5% S coal)
- Outlet SO_2 concentration: 1.2 lb/MM BTU (allowable)
- Reheat: 50°F above dew point (from 125 to 175°F)

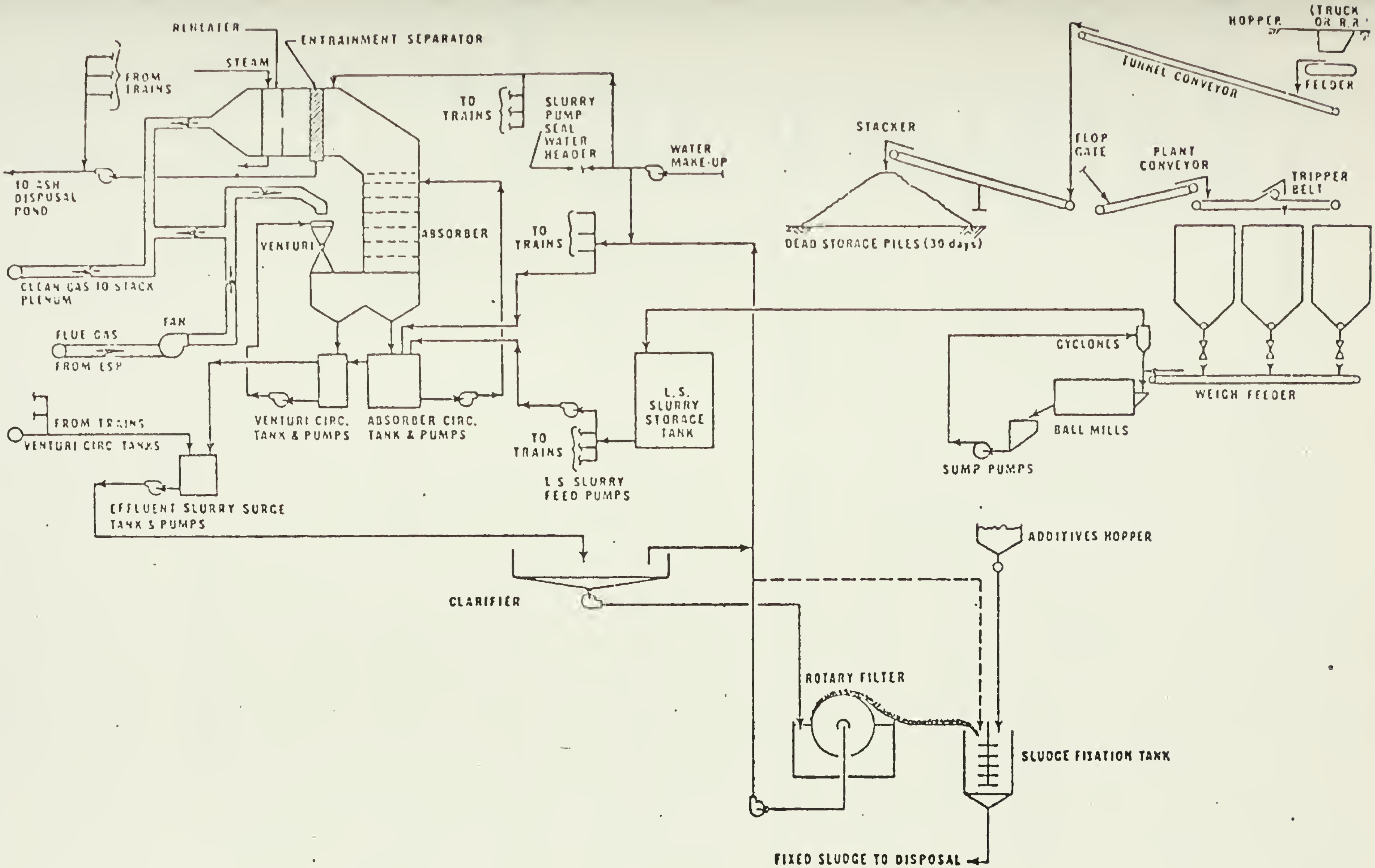


Figure D.1. Process Flow Sheet- Limestone Slurry Scrubbing System

- Limestone consumption: 130% stoichiometric

Limestone System

Unloading hopper: 100 ton capacity

Dead storage pile: 17,280 tons (30 day storage)

Feeders, Conveyors: Capacity = 139.2 ton/hr (5.8 x maximum limestone flow)

Live storage silos: 3 @ 576 tons capacity (3 days storage)

Ball mills: 2-15 tons/hr capacity units

Limestone slurry storage tank: 2 tanks @ 35,535 ft^3 capacity (24 hours storage)

Limestone slurry feed pumps: 2 pumps/train with 1 spare for each 2 operating pumps

Raw water pumps: 2

Clarifier: 3 units

Sludge pond: 142 acre pond with 50 foot dike which would cover the remaining plant life of 30 years

Scrubbing System (each train)

Fan: 1-100% unit

Type - Double inlet centrifugal

ΔP = 16.0" H_2O

Absorber: type - TCA with 2 beds

ΔP = 10" H_2O

L/G = 65 GPM/MACFM (inlet gas to absorber scrubber)

Slurry concentration = 8% (wt.)

SO_2 removal = 85%+

Gas velocity = 10 FPS, absorber

Circulating tank - 10 minutes retention, absorber

Pumps = 4/train plus 1 spare pump for each train

Entrainment Separator: Chevron vane type

Number passes = 2

$\Delta P = 2'' \; H_2O$

Gas velocity = 7 FPS

Reheater: type - indirect tubular

$\Delta T = 50°F$ (inlet temperature = 125°F; outlet temperature = 175°F)

Heating medium - low pressure steam

B. Design Rationale

The design rationale used in the study are listed below:

- The unloading hopper was sized to hold 100 tons in order to accomodate unloading of railroad cars as well as trucks.

- The limestone dead storage pile was sized for 30 days storage to allow the plant to continue operating in the event of an interruption in the supply of limestone.

- The live storage silos were sized for 3 days storage.

- The feeders and conveyors were sized at 5.8 times the maximum limestone flow to allow the unloading of limestone to take place during a 40 hour week while the plant operates continuously.

- 2-15 tons/hr capacity ball mills were provided and sized to allow the power plant to generate at maximum capacity while burning high sulfur content coal. In the event 1 mill was out of service, the other mill could keep the plant operating for 64 hours.

- The limestone slurry storage tanks were sized for 24 hours storage to allow the scrubbing trains to continue operating for 59 hours with 1 mill out of service or for 24 hours if maintenance required complete shutdown of the 2 ball mills.

- In general, all pumps in the process are provided with spares.

- Three thickeners and a new pond (142 acres) were used with diking to provide sufficient pond space for the life of the plant. The thickener concentrates the effluent slurry from 15% solids to 30% solids and then discharges the 30% effluent slurry to the vacuum filtration units. The effluent leaves the filtration unit with a slurry 60% by weight and then enters a mixing tank where the fixation additives are stirred in with the 60% slurry and then pumped to the sludge pond.

- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has 2 beds of hollow plastic spheres which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 GPM/MACFM (inlet gas to the absorber) and a pressure drop of 7" H_2O. Slurry concentration will be 8%; gas velocity in the unit will be 10 FPS; and SO_2 removal is specified to be about 85% plus. The size of turbulent contact absorbers will be 15' x 35' approximately in cross-section and will treat 375,000 ACFM, respectively of saturated gas. Four absorbers will be required for this unit.

- Each absorber has a circulating tank sized to provide a 10-minute retention time based on the slurry circulating rate. This retention time is essentially the same as that reported by others and should provide sufficient time for desupersaturation and thus reduce scaling potential.

- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O. Design of the unit is based on information from C-E, Chemico and UOP.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for it for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground-level concentration, etc. For this study, a reheat ΔT of 50°F was used; this is believed to be about the minimum acceptable value. Obviously, the lowest acceptable reheat ΔT should be chosen since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

  An indirect finned tubular heat exchanger was selected for the reheater. The first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas which enters at its dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low pressure saturated steam. Pressure drop through the reheater is calculated to be about 4" H_2O.

- Based on experience at an existing installation, a retractable soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers will be on the entry side, the remainder on the exit side of the heat exchanger.

- Cost of reheat was based purely on a coal conversion cost in BTU's.

*Universal Oil Products Company (Air Correction Division)

APPENDIX E

Basis of Wellman-Lord Process Design

[Excerpted from PEDCo-Environmental Specialists, Inc., Flue Gas Desulfurization Process Cost Assessment, (Washington, D.C.: U.S. Environmental Protection Agency, 1975)]

A. Design Values

The process design basis for the Wellman-Lord system used in this study was determined after review of process designs used or proposed for use at various installations and discussions with Davy Power Gas. Figure E.1 presents a typical process flow sheet for this process.

The plant evaluated for illustration of design basis . . . is a single 500 MW, pulverized-coal-fired boiler. The coal burned has a heating value of 12,000 BTU/lb, and a 3.5 percent sulfur content. The allowable sulfur dioxide emission rate is the New Source Performance Standard Limitation of 1.2 lb/MM BTU of heat input. The average annual capacity factor is 60 percent. The plant is assumed to be meeting particulate emission rate limitations and thus requires no additional particulate control.

Values of the major overall design parameters are tabulated below:

- Flue gas rate: 1,500,000 ACFM
- Flue gas temperature: 310°F
- Flue gas pressure: atmospheric
- Average inlet SO_2 concentration: 5.54 lb/MM BTU (3.5% S coal)
- Outlet SO_2 concentration: 1.2 lb/MM BTU (allowable)
- Reheat: 50°F above dew point (from 125 to 175°F)
- Soda ash consumption: 5% stoichiometric

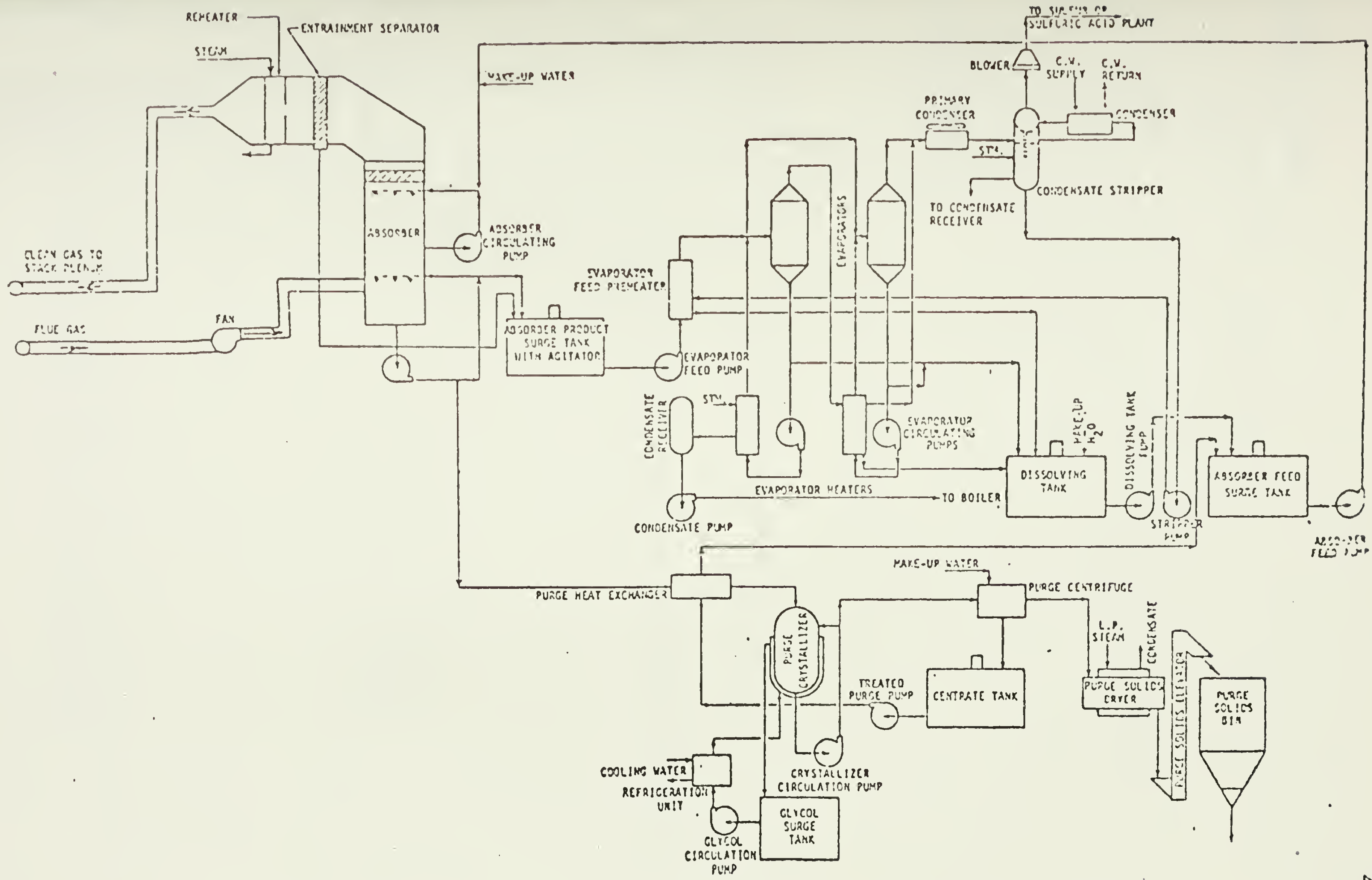


Figure E.1. Typical Process Flow Sheet of Wellman-Lord SO_2 Scrubbing System

Soda Ash System

Unloading Hopper: 100 ton capacity

Storage Silo: 893 tons (30 day storage)

Feeders: Capacity = 3.72 tons (3.0 x maximum soda ash flow)

Na_2CO_3 Slurry Storage Tank: 570 ft^3 (4 hours)

Na_2CO_3 Slurry Feed Pump: 1 pump

Raw Water Pumps: 2

Scrubbing System

Fan: 1-100% unit

Type - Double inlet centrifugal

ΔP = 16.0" H_2O

Absorber: Type - Sieve tray with 2 stage (4 required)

ΔP = 8" H_2O

L/G = 3 GPM/MACFM/ stage (inlet gas to absorber scrubber)

Slurry Concentration = 25% (wt.)

SO_2 Removal = 90%+

Gas Velocity = 8 FPS

Solution Storage Tanks - 24 hour storage

Pumps = 2/stage plus 1 spare pump for each unit

Entrainment Separator: Chevron vane type (2/absorber)

Number passes = 2

ΔP = 2" H_2O

Gas Velocity = 7 FPS

Purge Treatment:

Refrigeration: Temperature 40°F; Flow - 5% of recirculation rate

Centrifuge: Solids - 5% of stoichiometric Na_2CO_3

Acid Plant:

Size: 415 tons/day (125% of average SO_2 flow)

SO_2 Regeneration:

Evaporators: 30% slurry of Na HSO_3 based on SO_2 absorbed. Evaporators are sized for one hour retention and 50% free space.

Reboilers: 7.5°F temperature rise; 8 lbs of steam per lb of SO_2

Stripper: Overhead is 1 lb SO_2 and 1 lb H_2O

Reheater: type - indirect tubular

ΔT = 50°F (inlet temperature = 125°F;
Outlet temperature = 175°F)

Heating Median - low pressure steam

B. Design Rationale

The design rationale used in the study are listed below:

- The soda ash storage silo was sized for 30 days storage to allow the plant to continue operating in the event of an interruption in the supply of soda ash.
- The feeders were sized at 3.0 times the maximum soda ash flow.
- The soda ash slurry storage tank was sized for 4 hours storage.
- In general, all critical pumps in the process are provided with spares.
- A sieve tray was selected for removal of the bulk of the SO_2. This unit has 2 stages of sieve trays to provide the contact area necessary for mass transfer to SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 3 GPM/MACFM/stage (inlet gas to the absorber) and a pressure drop of 8" H_2O. Slurry concentration will be 25%; gas velocity in the unit will be 8 FPS; and SO_2 removal is specified to be about 90%. Four units will be required and each will treat 375,000 ACFM of saturated gas.
- The absorbers have common solution storage tanks sized to provide a 24 hour storage of the slurry. This storage time allows the absorbers to operate for approximately 24 hours in the event the acid plant should break down.
- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for it for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground-level concentration, etc. For this study, a reheat ΔT of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

  An indirect finned tubular heat exchanger was selected for the reheater. The first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas which enters at its dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low pressure saturated steam. Pressure drop through the reheater is calculated to be about 4" H_2O.

- Based on experience at an existing facility, a retractable soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers will be on the entry side, the remainder on the exit side of the heat exchanger.

- Cost of reheat was based purely on a coal conversion cost in BTU's.

- Purge treatment equipment was based for the most part on TVA cost estimates.

- The acid plant cost was based on costs furnished by Wellman-Lord.

Appendix F

Description of the Atmospheric Pollutant Dispersion Model

The procedure used for estimating the dispersion of atmospheric pollutants is described by D. Bruce Turner in the Workbook of Atmospheric Dispersion Estimates (Research Triangle Park, N.C.: United States Environmental Protection Agency, 1970). The salient features and important assumptions of this model are outlined here:

The coordinate system of the model is illustrated in Figure F.1. The origin is at ground level beneath the point of emission. The x-axis extends horizontally in the mean wind direction, the y-axis extends horizontally perpendicular to the mean wind direction, and the z-axis extends verticallt. The smoke stack plume is assumed to travel in a direction parallel to the x-axis.

The model makes three fundamental assumptions about the spread of the plume after it leaves the stack. First, diffusion of the plume in the direction of travel (i.e., along the x-axis) is neglected. Thus, the pollutant emission rate is assumed to be constant and continuous. Second, the spread of the plume in both the horizontal (along the y-axis) and vertical planes is assumed to have a Gaussian, or normal distribution. And third, it is assumed that total reflection of the plume takes place at the earth's surface -- there is no disposition or reaction of the pollutants at ground level. Therefore, the vertical diffusion expression includes an unreflected and reflected component equation for the concentration of a pollutant at points x, y, and z from a height H is as follows:

$$\chi(x,y,z,H) = \frac{Q}{2\pi\sigma_y\sigma_z u} \exp\left[-1/2\left(\frac{y}{\sigma_y}\right)^2\right]\left\{\exp\left[-1/2\left(\frac{z-H}{\sigma_z}\right)^2\right] + \exp\left[-1/2\left(\frac{z+H}{\sigma_z}\right)^2\right]\right\}$$

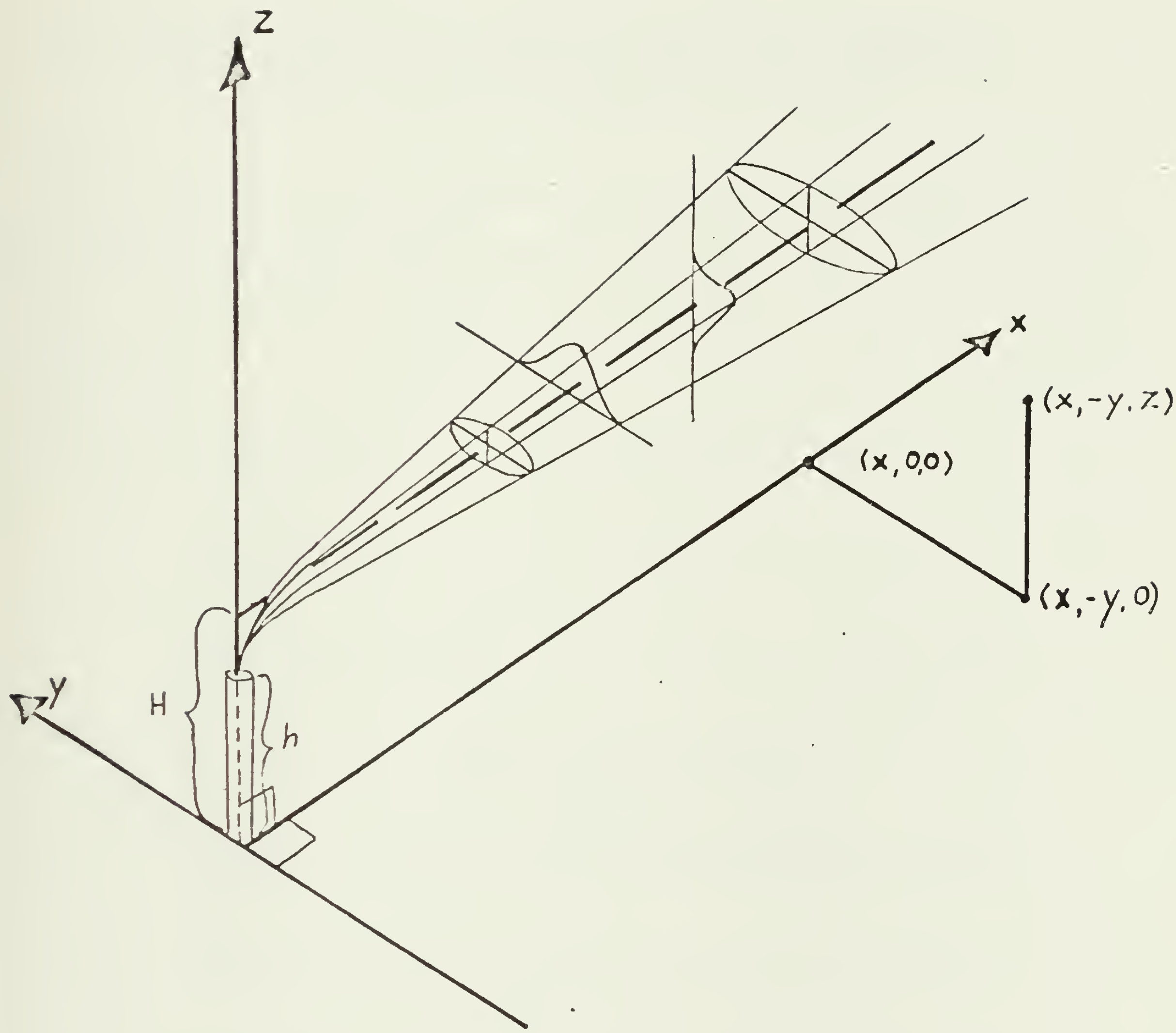


FIGURE F.1 COORDINATE SYSTEM of THE ATMOSPHERIC DISPERSION MODEL.

where

χ = the pollutant concentration in grams per cubic meter;

Q = the pollutant emission rate in grams per second;

u = the mean wind speed in meters per second;

σ_y, σ_z = the Gaussian standard deviation of plume concentrations in the horizontal and vertical directions;

H = the effective stack height in meters; the height at which the plume becomes essentially level; sum of the physical stack height and the plume rise.

The values of σ_y and σ_z are a function of atmospheric stability and distance downwind from the emission source and can be determined from Figure 3.3 in Turner. The estimation of effective stack height is discussed in the text of this report.

The major assumptions of this model are summarized below:

(1) The pollutant source has a constant and continuous emission rate;

(2) There is no diffusion in the direction of plume travel (along the x-axis);

(3) The plume dispersion in the horizontal and vertical directions has a Gaussian distribution;

(4) The mean wind speed affecting the plume is u; there is no variation of wind speed or direction with vertical height;

(5) Total reflection of the plume occurs at the earth's surface;

(6) The sampling time for the estimated concentrations is 10 minutes;

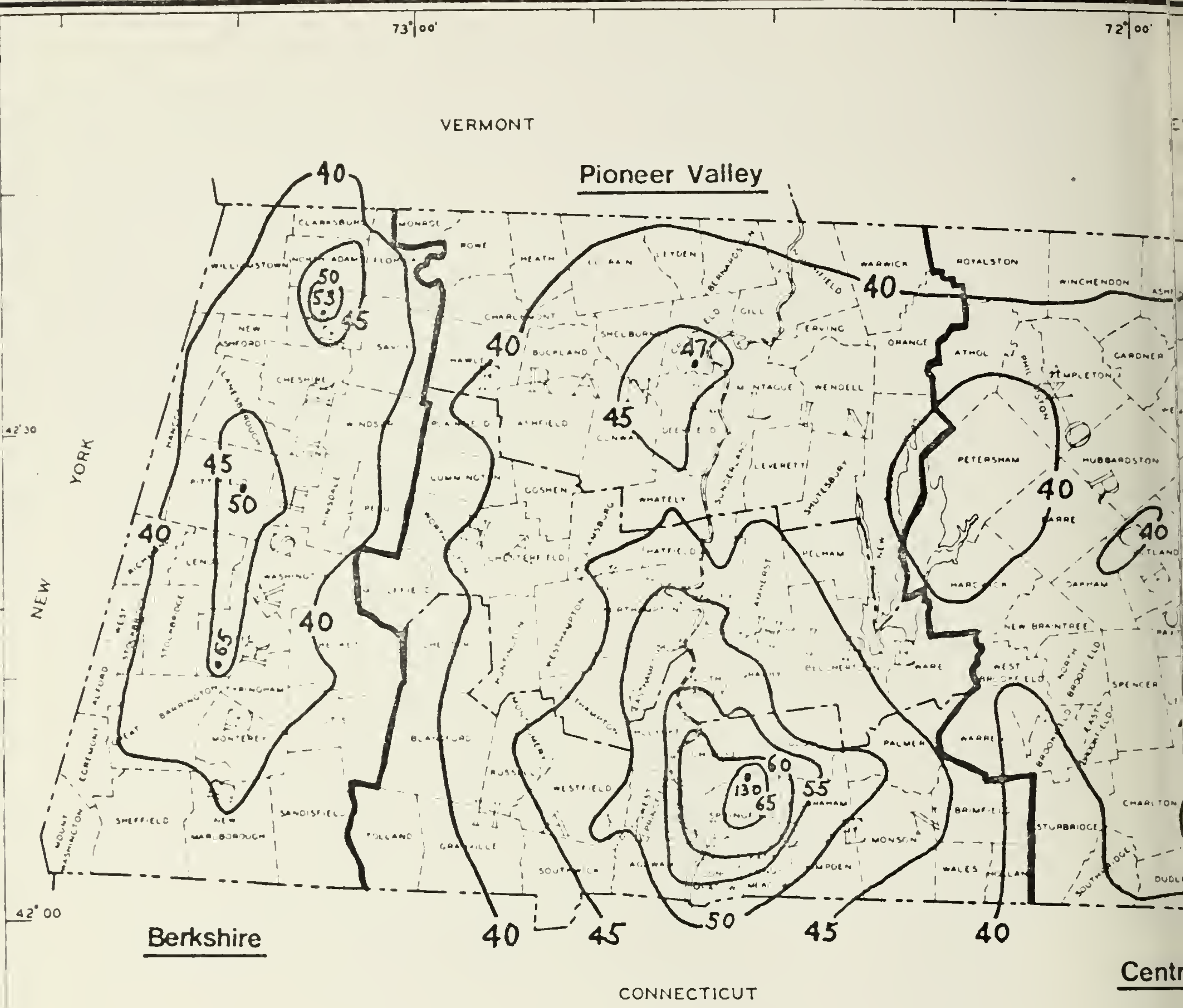
(7) Plume dispersion occurs over relatively smooth topography;

(8) The vertical height of the plume is in the lowest several hundred meters of the atmosphere.

Because of the assumptions that are made, the pollutant concentrations calculated from this model can only be considered "best estimates." Turner concludes that in certain cases the value of σ_z may be expected to be correct within a factor of two (uncertainties in σ_y will generally be less than those of σ_z). These cases are: (1) during all atmospheric stabilities for a distance downwind of a few hundred meters; (2) during neutral to moderately unstable atmospheric conditions for distances out to a few kilometers, and (3) during unstable conditions in the lower 1000 meters of the atmosphere with a marked inversion above the unstable layer, for distances out to 10 kilometers or more. The estimation of maximum ground-level pollutant concentrations, as described in the text, assumes atmospheric conditions which conform to the third case described above. In this instance, according to Turner, ground level plume centerline concentrations should be correct within a factor of 3, including errors associated with estimating σ_y and u.

Appendix G

Isopleths of Sulfur Oxide and Particulate Concentrations In Massachusetts: 1975 and 1985



1975 Annual Estimated Total Su
(TSP) Levels (µg/M³).
Note: Based on Regulation

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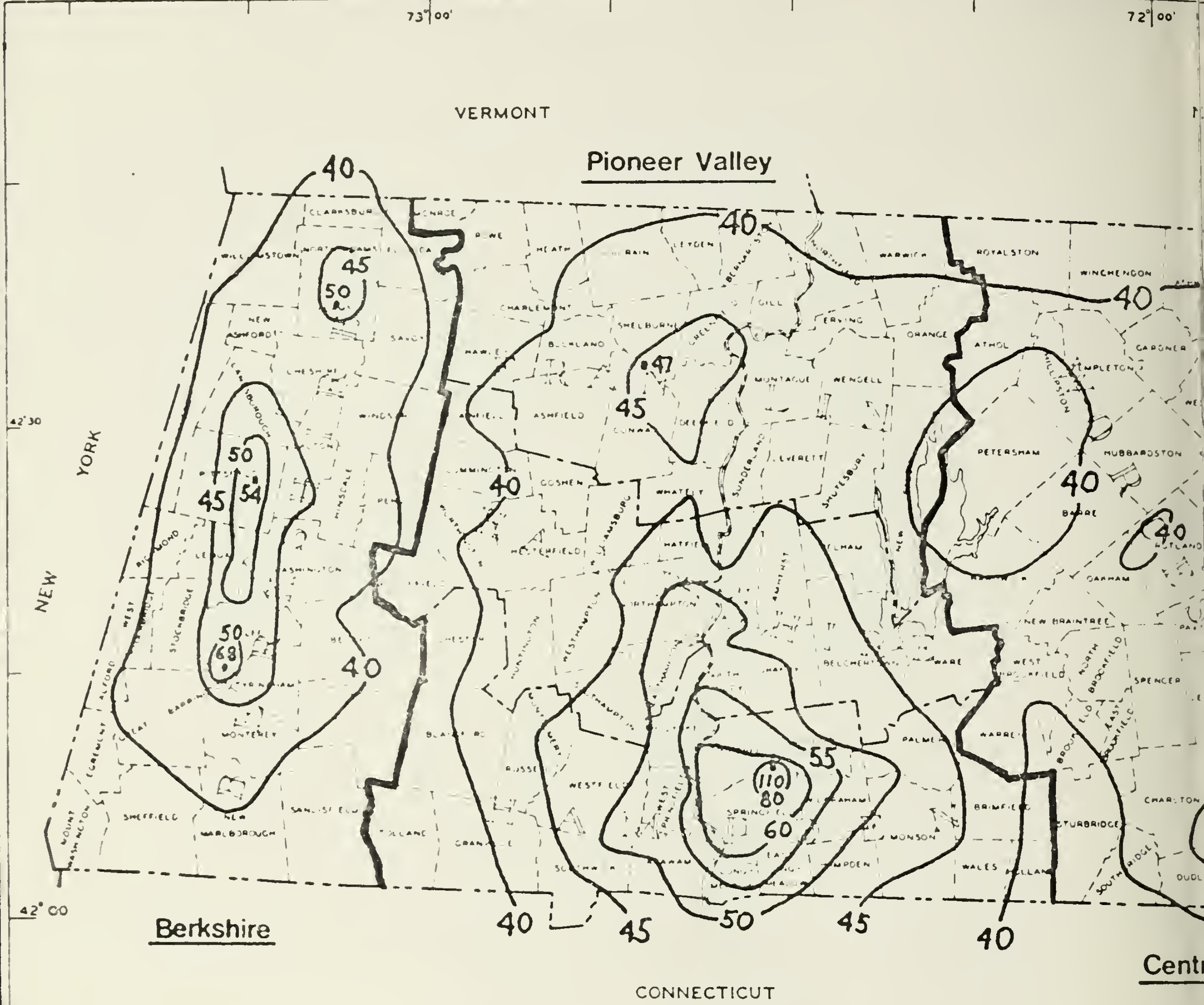
Department of Environmental Quality Engineering

Division of Air Quality Control

10 0 10 20 30 40

SCALE IN MILES


Merrimack Valley
Metropolitan Boston
Southeastern Massachusetts
71°00'
70°00'
SHIRE
ISLAND
ulate
1-76
UDES
SSET
BARNSTABLE
DUKES
NANTUCKET
PLYMOUTH
BRISTOL
40
45
50
55
49
53



1985	Annual Estimated Total Su
	(TSP) Levels ($\mu g/M^3$)
	Note: Based on Regulatio

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Division of Air Quality Control

10 0 10 20 30 40

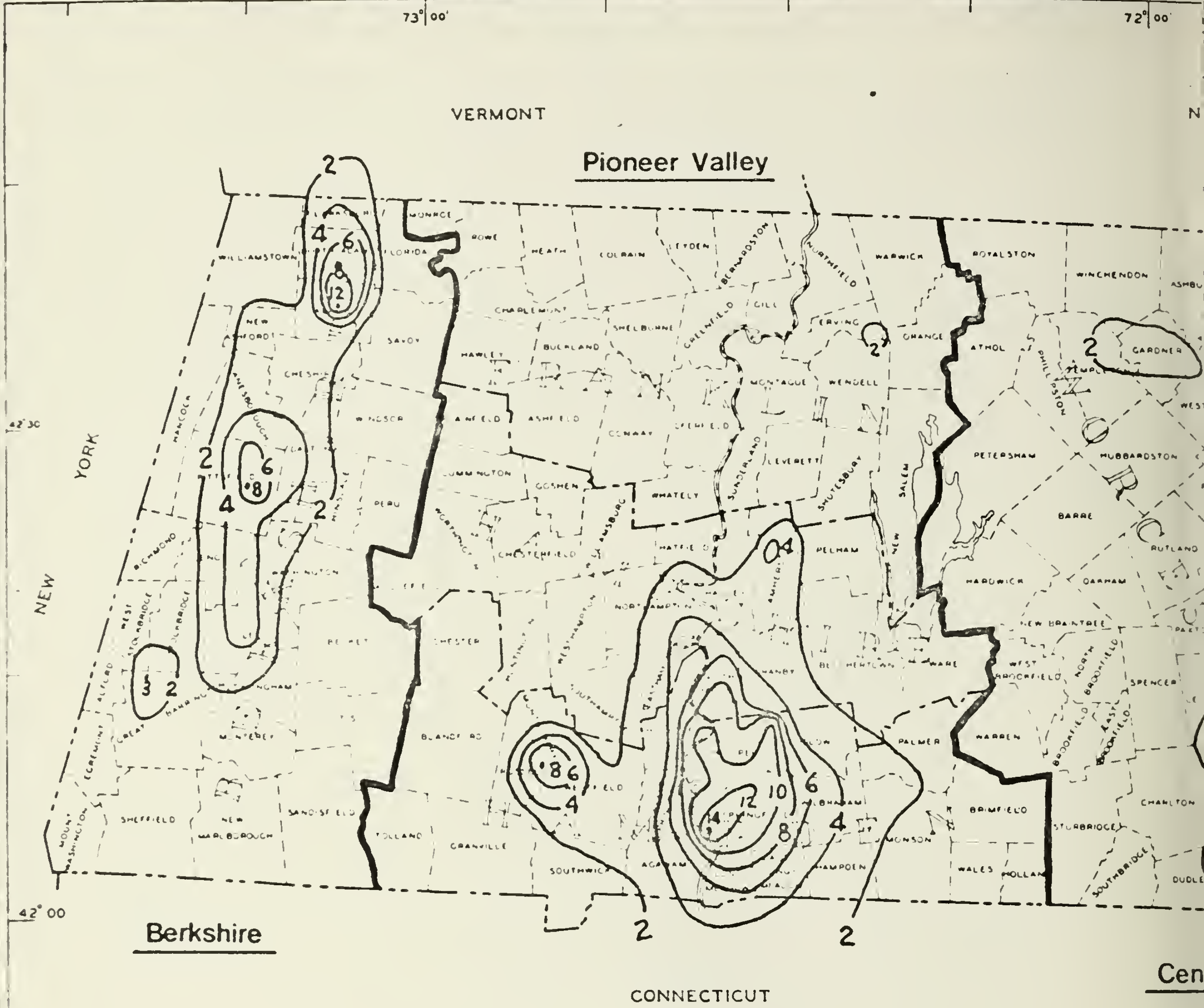
SCALE IN MILES

73°00'

72°00'

NOT


Merrimack Valley
Metropolitan Boston
Southeastern Massachusetts
SHIRE
ISLAND
ulate
-1-76
71° 00'
70° 00'
NANTUCKET
DUKES
BARNSTABLE
PLYMOUTH
40
45
50
55



1975	*Annual Estimated Sulfur*
	Levels (ppb).
	Note : Based on Regulati

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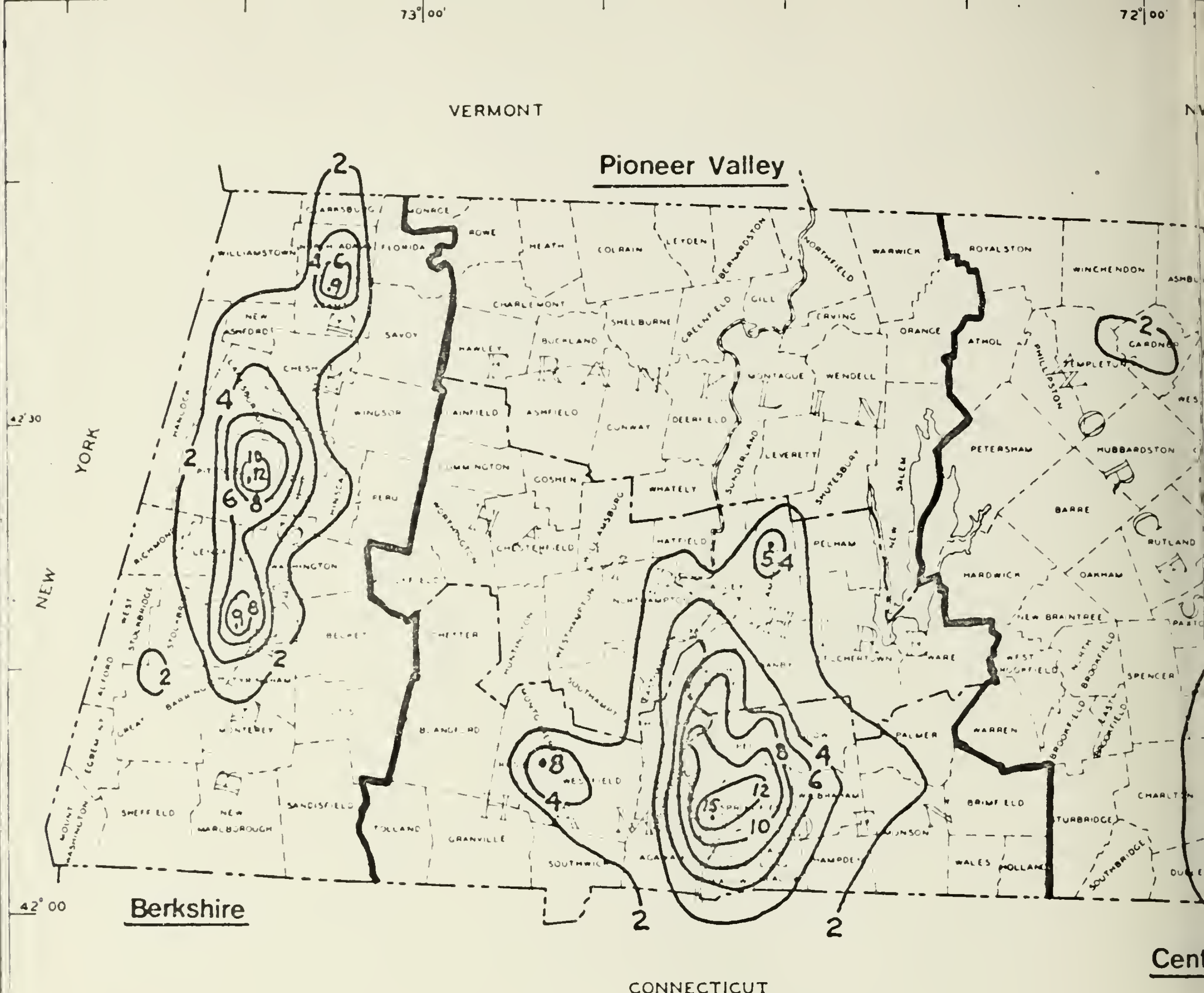
10 0 10 20 30 40

SCALE IN MILES

71°00'
70°00'
Merrimack Valley
Metropolitan Boston
Southeastern Massachusetts
42°30'
42°00'
41°30'
BARNSTABLE
DUKES
NANTUCKET
PLYMOUTH
BRISTOL



1985	Annual Estimated Sulfu
	Levels (ppb).
	Note: Based on Regulati

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Department of Environmental Quality Engineering

Division of Air Quality Control

NOTE

10 0 10 20 30 40

SCALE IN MILES

73°00' 72°00'

71°00'
70°00'
Merrimack Valley
Metropolitan Boston
Southeastern Massachusetts
ISLAND
5-1-76
AMESBURY
SALISBURY
WEST NEWBURY
NEWBURY
GEORGETOWN
ROWLEY
BOXFORD
IPSWICH
ESSEX
HAMILTON
GLOUCESTER
WENHAM
MANCHESTER
BEVERLY
DUNSTABLE
GROTON
WESTFORD
BILLERICA
LITTLETON
BEDFORD
CONCORD
STOW
LINCOLN
SUDBURY
MARLBOROUGH
DOVER
WALPOLE
SCITUATE
NORWELL
MARSHFIELD
HANOVER
PEMBROKE
DUXBURY
BROCKTON
EASTON
FOXBOROUGH
WRENTHAM
MANSFIELD
NORTON
TAUNTON
ATTLEBORO
KINGSTON
PLYMPTON
MIDDLEBOROUGH
CARVER
PLYMOUTH
LAKEVILLE
WAREHAM
ROCHESTER
MARION
WESTPORT
DARTMOUTH
TRURO
WELLFLEET
EASTHAM
ORLEANS
BREWSTER
DENNIS
YARMOUTH
BARNSTABLE
HARWICH
CHATHAM
BOURNE
SANDWICH
MASHPEE
FALMOUTH
WEST TISBURY
EDGARTOWN
CHILMARK
GAY HEAD
NANTUCKET
BARNSTABLE
PLYMOUTH
DUKES
NANTUCKET

Appendix H

Computerized Conceptual Cost Estimates For Steam-Electric Power Plants (CONCEPT)

Data Printout For a 1000 MWe Coal-Fired Plant

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON
COST BASIS: AT START OF CONSTRUCTION
DESIGN AND CONSTRUCTION PERIOD 1978.0 - 1985.0
40 HOUR WORK WEEK STRAIGHT INTEREST RATE = 8.0

ACCOUNT NUMBER	ACCOUNT TITLE	TOTAL COST
	DIRECT COSTS	
10	LAND AND LAND RIGHTS	$ 1000.
	PHYSICAL PLANT	
11	STRUCTURES AND SITE FACILITIES	40470.
12	BOILER PLANT EQUIPMENT	101303.
13	TURBINE PLANT EQUIPMENT	89696.
14	ELECTRIC PLANT EQUIPMENT	21378.
15	MISCELLANEOUS PLANT EQUIPMENT	6123.
	SUBTOTAL	$ 259019.
	SPARE PARTS ALLOWANCE	1516.
	CONTINGENCY ALLOWANCE	18320.
	SUBTOTAL	$ 278855.
	INDIRECT COSTS	
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES	15594.
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES	24534.
93	OTHER COSTS	9370.
94	INTEREST DURING CONSTRUCTION	95338.
	SUBTOTAL	$ 145296.
	START OF CONSTRUCTION COST	$ 425151.
	ESCALATION DURING CONSTRUCTION (6.18/YR)	$ 119228.
	TOTAL PLANT CAPITAL INVESTMENT = ($ 544/KW)	$ 544375.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON
BREAKDOWN OF PHYSICAL PLANT COSTS (THOUSANDS OF DOLLARS)

PHYSICAL PLANT			FACTORY EQUIPMENT COST	SITE LABOR MAN-HR	SITE LABOR COST	SITE MATERIAL COST
11	STRUCTURES AND SITE FACILITIES	40470.	1043.	(1380)	22265.	17162.
12	BOILER PLANT EQUIPMENT	101303.	51093.	(2330)	40989.	9321.
13	TURBINE PLANT EQUIPMENT	89696.	44598.	(1701)	30391.	14707.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SLMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON
BREAKDOWN OF PHYSICAL PLANT CCSTS (THOUSANDS CF DOLLARS)

PHYSICAL PLANT			FACTORY EQUIPMENT COST	SITE LABOR MAN-HR	SITE LABOR COST	SITE MATERIAL COST
11	STRUCTURES AND SITE FACILITIES	40470.	1043.	(1380)	22265.	17162.
12	BOILER PLANT EQUIPMENT	101303.	51093.	(2300)	40989.	9321.
13	TURBINE PLANT EQUIPMENT	89696.	44598.	(1701)	30391.	14707.
14	ELECTRIC PLANT EQUIPMENT	21378.	8224.	(582)	10546.	2607.
15	MISCELLANEOUS PLANT EQUIPMENT	6173.	1479.	(196)	3282.	1411.
	SUBTOTAL	259019.	106438.	(6159)	107373.	45209.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
10	LAND AND LAND RIGHTS				
101	LAND AND PRIVILEGE ACQUISITION	$ 0.	$ 0.	$ 1000.	1000.
102	RELOCATION OF BUILDINGS, UTILITIES, ETC.	$ 0.	$ 0.	$ 0.	0.
	TOTAL FOR ACCOUNT 10	$ 0.	$ 0.	$ 1000.	$ 1000.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
11	STRUCTURES AND SITE FACILITIES				
111	YARD WORK				
.1	GENERAL YARD IMPROVEMENTS	0.	1413.	673.	2086.
.2	WATERFRONT IMPROVEMENTS	0.	0.	0.	0.
.3	HIGHWAY AND RAILWAY ACCESS	0.	1124.	1250.	2374.
	SUBTOTAL.	$ 0.	$ 2537.	$ 1923.	$ 4460.
112	MAIN POWER STATION BUILDING				
.1	BASIC BUILDING STRUCTURES	0.	11813.	12097.	23910.
.2	BUILDING SERVICES	829.	4629.	1312.	6763.
	SUBTOTAL.	$ 829.	$ 16442.	$ 13409.	$ 30679.
113	ADMINISTRATION BUILDING				
.1	BASIC BUILDING STRUCTURES	0.	468.	414.	882.
.2	BUILDING SERVICES	214.	356.	150.	720.
	SUBTOTAL.	$ 214.	$ 825.	$ 563.	$ 1602.
114	INTAKE AND DISCHARGE STRUCTURES				
.1	SCREEN AND PUMP WELL	0.	2461.	1268.	3729.
.2	DISCHARGE STRUCTURES (IN 132.2)	0.	0.	0.	0.
.3	UNPRESSURIZED INTAKE AND DISCHARGE CONDUITS (IN 132.2)	0.	0.	0.	0.
	SUBTOTAL.	$ 0.	$ 2461.	$ 1268.	$ 3729.
	SUBTOTAL FOR ACCOUNT.	$ 1043.	$ 22265.	$ 17162.	$ 40470.
	CONTINGENCY (5.0%MTL-10.0%LABOR)	52.	2226.	859.	3137.
	SPARE PARTS (1.0%).	10.	-	172.	182.
	TOTAL FOR ACCOUNT 11	$ 1105.	$ 24491.	$ 18193.	$ 43789.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
12	BOILER PLANT EQUIPMENT				
121	STEAM GENERATING EQUIPMENT				
.1	BOILER AND ACCESSORIES	31381.	20542.	751.	52673.
.2	SOOT BLOWING SYSTEM	1297.	655.	169.	2122.
	SUBTOTAL.	$ 32678.	$ 21197.	$ 918.	$ 54793.
122	DRAFT SYSTEM				
.1	FORCED DRAFT FANS	616.	466.	319.	1400.
.2	INDUCED DRAFT FANS	0.	0.	0.	0.
.3	PRECIPITATORS	5015.	1737.	62.	6814.
.4	DRAFT FLUES AND BREECHING	0.	1697.	1576.	3223.
.5	PRECIPITATOR AND DUCT SUPPORTS	0.	1060.	966.	2026.
.6	STACKS AND FOUNDATIONS	0.	2818.	1832.	5452.
	SUBTOTAL.	$ 5631.	$ 7768.	$ 4712.	$ 18111.
123	COAL HANDLING AND STORAGE SYSTEMS				
.1	OUTDOOR COAL HANDLING SYSTEM				
.11	CONVEYORS, FEEDERS, CRUSHERS, ETC.	$ 2665.	$ 1687.	$ 89.	4441.
.12	CRUSHER HOUSE AND OTHER STRUCTURES	502.	496.	18.	1015.
.13	LIGHTING, DRAINAGE, AND FIRE PROTECTION	0.	397.	177.	574.
.14	DUST CONTROL EQUIPMENT	72.	40.	9.	122.
.15	MOBILE EQUIPMENT	394.	0.	0.	394.
.16	FOUNDATIONS, PITS, AND TUNNELS	0.	3180.	1255.	4435.
	SUBTOTAL.	$ 3632.	$ 5799.	$ 1547.	$ 10977.
.2	INDOOR DISTRIBUTION SYSTEM	251.	109.	11.	371.
.3	BUNKERS AND ACCESSORIES	20.	381.	516.	917.
.4	PULVERIZERS AND ACCESSORIES	5732.	992.	124.	6843.
.5	IGNITION OIL SYSTEM	40.	77.	19.	135.
	SUBTOTAL.	$ 9675.	$ 7359.	$ 2214.	$ 19247.
124	FUEL OIL STORAGE AND HANDLING SYSTEMS				
.1	OIL STORAGE TANKS AND ACCESSORIES	0.	0.	0.	0.
.2	OIL TRANSFER AND BURNER PUMPS	0.	0.	0.	0.
.3	REHEATERS AND CONTROLS	0.	0.	0.	0.
.4	FUEL OIL PUMP HOUSE	0.	0.	0.	0.
.5	HOT WATER TRACING EQUIPMENT	0.	0.	0.	0.
.6	PIPING	0.	0.	0.	0.
.7	IGNITION OIL SYSTEM	0.	0.	0.	0.
	SUBTOTAL.	$ 0.	$ 0.	$ 0.	$ 0.
125	NATURAL GAS SUPPLY AND HANDLING SYSTEMS				
.1	PIPELINE FROM TRUNK TO PLANT INCLUDING METERING STA.	0.	0.	0.	0.
.2	PLANT PIPING	0.	0.	0.	0.
	SUBTOTAL.	$ 0.	$ 0.	$ 0.	$ 0.
126	ASH AND DUST HANDLING SYSTEMS				
.1	BOTTOM ASH HANDLING SYSTEM	638.	1231.	434.	2303.
.2	FLY ASH AND DUST HANDLING SYSTEM	251.	1002.	583.	1836.
	SUBTOTAL.	$ 889.	$ 2233.	$ 1017.	$ 4139.
127	INSTRUMENTATION AND CONTROL				
.1	COMBUSTION AND FEEDWATER CONTROL EQUIPMENT	466.	149.	0.	615.
.2	BOILER GAGE BOARDS AND INSTRUMENTS	287.	198.	0.	485.
.3	MISCELLANEOUS BOILER PLANT INSTRUMENTS	143.	99.	0.	243.
.4	INSTRUMENT AND CONTROL PIPING	0.	496.	265.	761.
.5	COMPUTER EQUIPMENT	1325.	199.	0.	1524.
	SUBTOTAL.	$ 2221.	$ 1141.	$ 265.	$ 3627.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
128	MISCELLANEOUS SUSPENSE ITEMS				
.1	PAINTING	0.	794.	177.	971.
.2	PRELIMINARY OPERATION	0.	397.	19.	415.
	SUBTOTAL.	$ 0.	$ 1191.	$ 194.	$ 1385.
	SUBTOTAL FOR ACCOUNT.	$ 51093.	$ 40889.	$ 9321.	$101303.
	CONTINGENCY (5.0%MTL-10.0%LABOR)	2555.	4089.	466.	7110.
	SPARE PARTS (1.0%).	511.	- - - -	53.	564.
	TOTAL FOR ACCOUNT 12	$ 54159.	$ 44978.	$ 9840.	$108977.

CATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1200 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
		COST (THOUSANDS OF DOLLARS)			
13	TURBINE PLANT EQUIPMENT				
131	TURBINE-GENERATORS				
.1	TURBINE-GENERATORS AND ACCESSORIES	27671.	1986.	352.	30017.
.2	FOUNDATIONS	0.	1176.	501.	1676.
.3	STANDBY EXCITERS	0.	0.	0.	0.
.4	LUBRICATING SYSTEM	56.	210.	118.	484.
.5	GAS SYSTEMS	72.	89.	30.	191.
.6	REHEATERS (IN 121.1)	0.	0.	0.	0.
.7	SHIELDING	0.	0.	0.	0.
.8	WEATHER-PROOF HOUSING	0.	0.	0.	0.
	SUBTOTAL	$ 27798.	$ 3482.	$ 1061.	$ 32341.
132	HEAT REMOVAL SYSTEMS				
.1	WATER INTAKE FACILITIES	156.	119.	23.	298.
.2	CIRCULATING WATER SYSTEMS				
.21	PUMPS	$ 1097.	$ 93.	$ 7.	1197.
.22	PIPING	0.	2636.	1779.	4414.
.23	DISCHARGE TUNNEL	0.	0.	0.	0.
.24	DISCHARGE CANAL AND STRUCTURES	0.	0.	0.	0.
.25	DEICING PUMP PIT STRUCTURE	0.	0.	0.	0.
	SUBTOTAL	$ 1097.	$ 2729.	$ 1785.	$ 5611.
.3	COOLING TOWERS	4605.	6740.	425.	11770.
.4	OTHER SYSTEMS REJECTING HEAT TO THE ATMOSPHERE	0.	0.	0.	0.
	SUBTOTAL	$ 5857.	$ 9598.	$ 2233.	$ 17679.
133	CONDENSING SYSTEMS				
.1	CONDENSERS	3003.	1142.	30.	4175.
.2	CONDENSATE SYSTEM	573.	1905.	1049.	3525.
.3	GAS REMOVAL SYSTEM	215.	151.	95.	461.
.4	TURBINE BYPASS SYSTEM	0.	0.	0.	0.
	SUBTOTAL	$ 3791.	$ 3198.	$ 1174.	$ 8161.
134	FEED HEATING SYSTEM				
.1	REGENERATIVE HEAT EXCHANGERS	2574.	258.	30.	[illegible]
.2	PUMPS	2368.	352.	22.	2742.
.3	PIPING AND TANKS	0.	5500.	4125.	[illegible]
	SUBTOTAL	$ 4942.	$ 5010.	$ 4210.	$ [illegible]
135	OTHER TURBINE PLANT EQUIPMENT				
.1	MAIN STEAM OR OTHER VAPOR PIPING	0.	4944.	4415.	9361.
.2	TURBINE AUXILIARIES	9.	763.	342.	1114.
.3	AUXILIARIES COOLING SYSTEM	184.	743.	579.	1505.
.4	MAKEUP TREATMENT SYSTEMS	1144.	497.	392.	1533.
.5	SECONDARY CHEMICAL TREATMENT SYSTEM	14.	20.	15.	52.
.8	CENTRAL LUBRICATION SERVICE SYSTEM	0.	0.	0.	0.
	SUBTOTAL	$ 1351.	$ 6955.	$ 5735.	$ [illegible]
136	INSTRUMENTATION AND CONTROL				
.1	PROCESS I & C EQUIPMENT	858.	298.	26.	1182.
.2	INSTRUMENT AND CONTROL PIPING	0.	575.	135.	[illegible]
	SUBTOTAL	$ 858.	$ 894.	$ 203.	$ 1955.
137	MISCELLANEOUS SUSPENSE ITEMS				
.1	PAINTING	0.	546.	62.	608.
.2	PRELIMINARY OPERATION	0.	598.	18.	614.
.3	QUALIFICATION OF WELDERS	0.	97.	26.	[illegible]
	SUBTOTAL	$ 0.	$ 1241.	$ 106.	$ 1347.

CATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1200 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
		COST (THOUSANDS OF DOLLARS)			
	SUBTOTAL FOR ACCOUNT	$ 44598.	$ 30371.	$ 14727.	$ [illegible]
	CONTINGENCY (5.0EQPT-10.0%LABOR)	2230.	3039.	735.	[illegible]
	SPARE PARTS (1.0%)	555.	[illegible]	[illegible]	[illegible]
	TOTAL FOR ACCOUNT 13	$ 51225.	$ [illegible]	$ [illegible]	$ [illegible]

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
	SUBTOTAL FOR ACCOUNT.	$ 44598.	$ 30391.	$ 14717.	$ 89696.
	CONTINGENCY (5.0%MTL-10.0%LABOR)	2230.	3039.	735.	6004.
	SPARE PARTS (1.0%).	446.	- - -	147.	593.
	TOTAL FOR ACCOUNT 13	$ 47274.	$ 33430.	$ 15599.	$ 96293.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
14	ELECTRIC PLANT EQUIPMENT				
141	SWITCHGEAR				
.1	GENERATOR EQUIPMENT	21.	20.	2.	43.
.2	STATION SERVICE	1929.	466.	110.	2505.
	SUBTOTAL	$ 1950.	$ 486.	$ 112.	$ 2548.
142	STATION SERVICE EQUIPMENT				
.1	TRANSFORMERS	809.	126.	10.	945.
.2	LOW VOLTAGE SUBSTATIONS AND TRANSFORMERS	1448.	342.	9.	1799.
.3	BATTERY SYSTEMS	40.	26.	3.	69.
.4	DIESEL ENGINE GENERATORS	177.	30.	5.	212.
.5	GAS TURBINE GENERATORS	2303.	693.	245.	3239.
.6	MOTOR GENERATOR SETS	116.	15.	2.	133.
	SUBTOTAL	$ 4892.	$ 1230.	$ 275.	$ 6397.
143	SWITCHBOARDS				
.1	MAIN CONTROL BOARD FOR ELECTRIC SYSTEMS	284.	92.	17.	393.
.2	AUXILIARY POWER AND SIGNAL BOARDS	13.	9.	2.	24.
	SUBTOTAL	$ 297.	$ 102.	$ 19.	$ 418.
144	PROTECTIVE EQUIPMENT				
.1	GENERAL STATION GROUNDING SYSTEM	0.	305.	149.	454.
.2	FIRE PROTECTION SYSTEM	0.	18.	12.	31.
	SUBTOTAL	$ 0.	$ 323.	$ 161.	$ 484.
145	ELECTRICAL STRUCTURES AND WIRING CONTAINERS				
.1	CONCRETE CABLE TUNNELS, TRENCHES, AND EVELOPES	0.	148.	87.	235.
.2	CABLE TRAYS AND SUPPORTS	248.	924.	44.	1216.
.3	CONDUIT	0.	2438.	542.	2981.
.4	OTHER STRUCTURES	0.	49.	15.	62.
	SUBTOTAL	$ 248.	$ 3558.	$ 688.	$ 4494.
146	POWER AND CONTROL WIRING				
.1	GENERATOR BUS WORK	703.	307.	10.	1020.
.2	STATION SERVICE POWER WIRING	234.	2139.	905.	3278.
.3	CONTROL WIRING	0.	1847.	350.	2197.
.4	INSTRUMENT WIRING	0.	554.	87.	642.
	SUBTOTAL	$ 937.	$ 4847.	$ 1353.	$ 7137.
	SUBTOTAL FOR ACCOUNT	$ 8224.	$ 10546.	$ 2607.	$ 21379.
	CONTINGENCY (5.0%MTL-10.0%LABOR)	411.	1055.	130.	1596.
	SPARE PARTS (1.0%)	82.	- - -	26.	108.
	TOTAL FOR ACCOUNT 14	$ 8718.	$ 11601.	$ 2765.	$ 23083.

ACCOUNT NUMBER	ACCOUNT TITLE	COST (THOUSANDS OF DOLLARS) FACTORY EQUIPMENT	SITE LABOR	SITE MATERIALS	TOTAL
15	MISCELLANEOUS PLANT EQUIPMENT				
151	TRANSPORTATION AND LIFTING EQUIPMENT				
.1	CRANES AND HOISTS	276.	113.	9.	398.
.2	RAILWAY AND ROADWAY EQUIPMENT	0.	0.	0.	0.
	SUBTOTAL	$ 276.	$ 113.	$ 9.	$ 398.
152	AIR, WATER, AND STEAM SERVICE SYSTEMS				
.1	AIR SYSTEMS	85.	406.	129.	620.
.2	WATER SYSTEMS	163.	1761.	1195.	3118.
.3	AUXILIARY HEATING STEAM	283.	712.	70.	1065.
	SUBTOTAL	$ 531.	$ 2878.	$ 1394.	$ 4803.
153	COMMUNICATIONS EQUIPMENT				
.1	LOCAL COMMUNICATIONS SYSTEMS	57.	119.	0.	175.
.2	SIGNAL SYSTEMS	28.	52.	0.	80.
	SUBTOTAL	$ 85.	$ 178.	$ 0.	$ 263.
154	FURNISHINGS AND FIXTURES				
.1	SAFETY EQUIPMENT	35.	0.	0.	35.
.2	SHOP, LABORATORY, AND TEST EQUIPMENT	283.	59.	9.	351.
.3	OFFICE EQUIPMENT AND FURNISHINGS	71.	0.	0.	71.
.4	CHANGE ROOM EQUIPMENT	21.	4.	0.	25.
.5	ENVIRONMENTAL MONITORING EQUIPMENT	0.	0.	0.	0.
.6	DINING FACILITIES	177.	43.	0.	220.
	SUBTOTAL	$ 587.	$ 113.	$ 9.	$ 707.
	SUBTOTAL FOR ACCOUNT	$ 1479.	$ 3282.	$ 1411.	$ 6173.
	CONTINGENCY (5.0%MTL-10.0%LABOR)	74.	328.	71.	473.
	SPARE PARTS (1.0%)	15.		15.	25.
	TOTAL FOR ACCOUNT 15	$ 1568.	$ 3610.	$ 1496.	$ 6674.

DATE 11/30/76 CONCEPT PHASE III

UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)

1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST($1000)
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES	
911	TEMPORARY FACILITIES	$ 4899.
912	CONSTRUCTION EQUIPMENT	$ 7926.
913	CONSTRUCTIONS SERVICES.	$ 3170.
	TOTAL FOR ACCOUNT 91	$ 15994.

DATE 11/30/76 CONCEPT PHASF III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST($1000)
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES	
921	ENGINEERING SERVICES	$ 12297.
922	CONSTRUCTION MANAGEMENT SERVICES	$ 12297.
	TOTAL FOR ACCOUNT 92	$ 24594.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST($1000)
93	OTHER COSTS	
931	TAXES AND INSURANCE	$ 6913.
932	STAFF TRAINING AND PLANT STARTUP	$ 153.
933	OWNERS G & A	$ 2304.
	TOTAL FOR ACCOUNT 93	$ 9370.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON

ACCOUNT NUMBER	ACCOUNT TITLE	COST($1000)
94	INTEREST DURING CONSTRUCTION	
941	PHYSICAL PLANT AND ASSOCIATED INDIRECT COSTS	$ 94696.
942	LAND AND LAND RIGHTS	$ 641.
	TOTAL FOR ACCOUNT 94	$ 95338.

DATE 11/30/76 CONCEPT PHASE III
UNIT 1 CAPITAL INVESTMENT SUMMARY (THOUSAND DOLLARS)
1000 MWE COALNET POWER PLANT BOSTON